

BP-16 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

BP-16-A-02

July 2015



ADMINISTRATOR'S PREFACE

These are transformative times for the electric utility industry in the Pacific Northwest. The region faces a series of critical issues—from the continuing impact of low natural gas prices on wholesale electricity prices and the cost of maintaining the region's aging assets, to emerging technologies, evolving markets, and new regulatory requirements. These and other factors are placing significant upward pressure on BPA's long-term cost structure, while total outstanding debt also continues to rise.

BPA's ability to continue to meet its multiple statutory obligations and public purpose objectives depends on maintaining our cost competitiveness and financial strength. This is a shared objective for the many customers, tribes, and others that rely on BPA for important services and programs.

This longer-term perspective weighed heavily in my decision-making, as did the near-term impact of the rate increase. I believe the final rates, which reflect a 7.1 percent power rate increase and a 4.4 percent transmission rate increase, properly balance the economic impacts of increased rates against the need for continued investments in the region's power and transmission assets while ensuring a high probability of recovering all of BPA's costs.

I understand that a rate increase of this magnitude creates additional hardship in communities that have yet to recover from difficult times, in particular those in the more rural parts of the region. I have considered this impact in my final decisions and believe we have made cost reductions and taken other management actions to keep the rate increase at the lowest prudent level.

Power rates are increasing for several reasons, among them increased hydro system operations and maintenance costs and fish and wildlife expenses; the expiration of debt management actions that reduced capital costs; the automatic cost escalation under the 2012 Residential Exchange Program settlement; and higher transmission costs that are included in power rates. The transmission rate increase stems mainly from capital investments in the aging transmission system.

My decisions are designed to help achieve long-term rate stability and maintain financial viability. This course is consistent with my recent decision during the Integrated Program Review to convert funding for BPA's Energy Efficiency program from capital to expense, eliminating the growth of long-term energy efficiency debt and associated debt service costs without reducing our ability to help the region meet its energy efficiency goals.

My decisions also set the stage for continued regional conversations on issues that would benefit from collaborative discussions with all interested stakeholders. For example, although I did not commit additional financial reserves to mitigate the transmission rate increase, BPA will work with stakeholders to develop disciplined financial policies that will equitably apply to both power and transmission rates, including the use of financial reserves and risk mitigation measures in support of BPA's enduring financial strength.

I also believe collaboration is the best way to address concerns that policies in California may have devalued long-term firm transmission capacity on the Southern Intertie. I believe that seams issues exist and must be addressed. Before adopting a ratemaking solution, however, such as significantly increasing the Southern Intertie hourly non-firm rate, BPA will seek clarity on the extent of the issue, conduct a broader examination of seams issues with the involved parties, and evaluate both ratemaking and non-ratemaking solutions. If the examination shows that a ratemaking solution is necessary to protect BPA's ability to sell long-term transmission capacity, BPA may conduct an expedited 7(i) rate proceeding prior to the BP-18 rate case to address any changes needed. I am determined to preserve the value of our assets, for both BPA's financial stability and the benefit of all of our customers and the region.

I have decided to retain the Montana Intertie rate rather than roll the costs of the Montana Intertie into the transmission network rates. Some parties argue that rolling in these costs would aid the development of renewable resources in Montana. I have concluded, however, that elimination of the Montana Intertie rate would have little effect on renewable development in Montana at this time. As demonstrated by the nearly 5,000 megawatts of wind energy connected to the Federal transmission system, BPA fully supports the development of clean energy resources. I believe the involved parties can achieve the best outcome by collaborating on a planning process and a financial plan to share the risks of increased costs, which could result from eliminating the Montana Intertie rate. BPA supports and will participate in a thoughtful, cohesive process to remove barriers to the development of renewables in Montana.

As steward of the low-cost, low-carbon regional power and transmission system that provides incredible value to the region's economy, BPA must maintain the system's value for generations to come. We will remain steadfastly focused on being the low-cost energy provider of choice when new power sales contracts are offered in the next decade.

BPA is planning a set of workshops for regional leaders to establish a common understanding of the strategic choices we face to maintain BPA's financial strength. Key issues will include our approach to capital investment in the hydropower and transmission systems, our internal operating costs, and our product delivery models, including energy efficiency. We expect these discussions to begin this fall. I look forward to working with all of you to address the region's challenges and opportunities.

Table of Contents

ADMINISTRATOR’S PREFACE	P-1
COMMONLY USED ACRONYMS AND SHORT FORMS	v
PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES	ix
1.0 GENERAL TOPICS.....	1
1.1 Introduction.....	1
1.1.1 Procedural History of this Rate Proceeding.....	1
1.1.1.1 Issue Workshops	1
1.1.1.2 BP-16 Rate Proceeding	1
1.1.1.3 Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Service Rates.....	3
1.1.1.4 Waiver of Issues by Failure to Raise in Briefs	4
1.1.2 Legal Guidelines Governing Establishment of Rates	4
1.1.2.1 Statutory Guidelines.....	4
1.1.2.2 The Broad Ratemaking Discretion Vested in the Administrator	5
1.1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates	5
1.1.3.1 Standard of Commission Review.....	6
1.2 Related Topics and Processes	6
1.2.1 Integrated Program Review	6
1.2.2 Energy Efficiency (EE) Program	7
1.2.3 2012 Residential Exchange Program Settlement Agreement	7
1.2.4 Rate Period High Water Mark Process	8
1.3 Procedural Issues	8
1.3.1 Changes to PNRR and CRAC Parameters.....	8
<i>Issue 1.3.1.1 Whether the Administrator should make adjustments to Planned Net Revenues for Risk (PNRR) or Cost Recovery Adjustment Clause (CRAC) parameters after litigants have filed their direct and rebuttal cases.</i>	<i>8</i>
2.0 POWER RATES AND POLICIES	13
2.1 Proposed Power Rate Increase.....	13
<i>Issue 2.1.1 Whether BPA should mitigate the proposed power rate increase to make its Priority Firm Power rates more competitive.</i>	<i>13</i>
2.2 Loads and Resources.....	15
2.3 Power Revenue Requirement.....	16
2.4 Power Risk and Market Price	17

	<i>Issue 2.4.1 Whether BPA should reflect secondary energy sales made at extra-regional points of delivery in BPA’s forecast of secondary revenue.</i>	18
2.5	Power Rate Development	26
2.5.1	Power Rate Development Changes.....	27
2.5.2	Demand Rate.....	30
	<i>Issue 2.5.2.1 Whether BPA should use an LMS100 or an F-class frame combustion turbine (F-class turbine) as the marginal resource to calculate the demand rate.....</i>	30
	<i>Issue 2.5.2.2 Whether BPA should include a planning reserve margin in calculating the demand rate.....</i>	34
	<i>Issue 2.5.2.3 Whether BPA should include a pipeline capacity release credit in the computation of the demand rate.....</i>	39
2.5.3	Load Growth Rate Billing Adjustment.....	47
	<i>Issue 2.5.3.1 Whether BPA should adopt the Load Growth Rate Billing Adjustment to recover the financial shortfall from customers that elected the Tier 2 Load Growth service and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate.....</i>	48
2.5.4	Transmission Scheduling Service (TSS) Cap.....	61
	<i>Issue 2.5.4.1 Whether BPA should remove the monthly TSS price cap for unspecified resource amounts.....</i>	61
3.0	GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICE RATE SCHEDULE	65
4.0	TRANSMISSION TOPICS.....	67
4.1	Segmentation.....	67
	<i>Issue 4.1.1 Whether equipment on the high side of delivery transformers and station general in facilities that provide delivery service should be assigned to the Network segment.</i>	69
	<i>Issue 4.1.2 Whether operations and maintenance (O&M) costs of facilities that are transferred to the Network should be allocated to the Utility Delivery segment.....</i>	77
	<i>Issue 4.1.3 Whether the cost of replacements for Utility Delivery facilities should be assigned to Utility Delivery customers.</i>	78
4.2	Transmission Revenue Requirement and Risk Analysis	79
4.2.1	Transmission Revenue Requirement	79
	<i>Issue 4.2.1.1 Whether BPA’s forecast of net interest expense for transmission should be reduced by \$26.3 million per year to compensate for BPA’s past forecasting errors.....</i>	80
	<i>Issue 4.2.1.2 Whether the repayment study should be modified to eliminate critical years, change the due date of \$49 million of projected debt from FY 2027 to FY 2024, and increase use of the rollover feature.....</i>	82

	<i>Issue 4.2.1.3 Whether the repayment of discretionary amortization should be scheduled based on the principle that debt with the highest interest rate is amortized first.</i>	83
	<i>Issue 4.2.1.4 Whether the repayment model should be made available to rate case parties.</i>	85
4.2.2	Transmission Risk Analysis	85
	<i>Issue 4.2.2.1 Whether financial reserves for risk attributed to Transmission Services should be used to mitigate the proposed transmission rate increase or fund transmission capital investment above \$15 million per year.</i>	86
	<i>Issue 4.2.2.2 Whether transmission risk mitigation objectives and CRAC and DDC mechanisms should be adopted.</i>	91
	<i>Issue 4.2.2.3 Whether either the level of transmission reserves or the fact that transmission TPP is above 95 percent indicates that the proposed transmission rates are too high.</i>	95
	<i>Issue 4.2.2.4 Whether maintaining transmission reserves for risk to support BPA's credit rating is a cost of the Federal transmission system.</i>	99
4.3	Transmission Rate Design	101
4.3.1	BP-14 O&M Error	102
	<i>Issue 4.3.1.1 Whether BPA should correct the misallocation of O&M costs made in the BP-14 rate case.</i>	102
4.3.2	Cost Allocation for BPA's Reliability Activities	105
	<i>Issue 4.3.2.1 Whether BPA should directly assign the projected costs of reliability compliance activities it performs under agreements it has with certain customers.</i>	105
4.3.3	Southern Intertie Hourly Non-Firm Rate	108
	<i>Issue 4.3.3.1 Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week is equitable.</i>	109
	<i>Issue 4.3.3.2 Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie.</i>	111
	<i>Issue 4.3.3.3 Whether BPA's ability to discount the hourly non-firm rate mitigates concerns regarding the stability of an hourly non-firm rate based on actual usage.</i>	113
4.3.4	Oversupply Rate	114
	<i>Issue 4.3.4.1 Whether Staff's cost allocation proposal should be adopted.</i>	116
	<i>Issue 4.3.4.2 Whether the allocation of oversupply costs to transmission rates complies with section 7(g) of the Northwest Power Act.</i>	119
	<i>Issue 4.3.4.3 Whether the OS-16 rate equitably allocates costs between Federal and non-Federal users of the transmission system under section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.</i>	120

4.3.5	Elimination of the Montana Intertie Rate	122
	<i>Issue 4.3.5.1 Whether to eliminate the IM rate and charge Network rates for Point-to-Point service over the Eastern Intertie starting at Townsend.....</i>	<i>122</i>
4.3.6	Network Segment Cost Allocation	126
	<i>Issue 4.3.6.1 Whether BPA should hold workshops regarding the Network segment cost allocation methodology after the BP-16 rate proceeding.....</i>	<i>126</i>
5.0	PARTICIPANT COMMENTS.....	129
6.0	NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS	131
6.1	Introduction.....	131
6.2	Business Plan EIS and ROD.....	131
6.3	Environmental Analysis.....	135
6.4	Public Comments	136
6.5	NEPA Decision.....	136
7.0	CONCLUSION	137

APPENDICES

Appendix A: Settlement Agreement

Appendix B: Power Rate Schedules and General Rate Schedule Provisions
(under separate cover)

Appendix C: Transmission, Ancillary and Control Area Service Rate Schedules
(under separate cover)

COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMP	Oversupply Management Protocol
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability
PF	Priority Firm Power
PFIA	Projects Funded in Advance
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
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)
RD	Regional Dialogue
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 rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES

Joint Parties in the BP-16 Rate Proceeding

Party Code	Joint Party	Joint Party Members
JP01	Joint Party 1	Avista Corporation (AC) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP02	Joint Party 2	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN)
JP03	Joint Party 3	Avista Corporation (AC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP04	Joint Party 4	Avista Corporation (AC) Iberdrola Renewables (IR) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP05	Joint Party 5	Avista Corporation (AC) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP06	Joint Party 6	Public Power Council (PP) Powerex Corporation (PX)
JP07	Joint Party 7	Public Power Council (PP) Industrial Customers of Northwest Utilities (IN)
JP08	Joint Party 8	Calpine Corporation (CP) Northwest & Intermountain Power Producers Coalition (NI) TransAlta Energy Marketing (TC)
JP09	Joint Party 9	Northwest Requirements Utilities (NR) Public Power Council (PP)
JP10	Joint Party 10	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Public Power Council (PP)
JP11	Joint Party 11	City of Tacoma (TA) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN)
JP12	Joint Party 12	Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)

JP13	Joint Party 13	Public Utility District No. 1 of Benton County (BC) Public Utility District No. 1 of Cowlitz County (CO) Eugene Water & Electric Board (EW) Public Utility District No. 1 of Franklin County (FR) Public Power Council (PP) City of Seattle (SE) Snohomish County PUD (SN)
JP14	Joint Party 14	City of Seattle (SE) Public Utility District No. 1 of Snohomish County (SN)
JP15	Joint Party 15	Industrial Customers of Northwest Utilities (IN) Northwest Requirements Utilities (NR) Public Power Council (PP) City of Seattle (SE)
JP16	Joint Party 16	Avista Corporation (AC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP17	Joint Party 17	Eugene Water & Electric Board (EW) Public Utility District No. 1 of Cowlitz County (CO)

1.0 GENERAL TOPICS

1.1 Introduction

The BP-16 rate proceeding establishes power and transmission rate schedules and general rate schedule provisions (GRSPs) for the Bonneville Power Administration (BPA) that replace existing rate schedules and GRSPs, which expire on September 30, 2015.

This Final Record of Decision (ROD) contains the decisions of the BPA Administrator, based on the record compiled in the BP-16 rate proceeding, with respect to the adoption of power, transmission, and ancillary and control area service rates for the two-year rate period October 1, 2015, through September 30, 2017 (fiscal years (FY) 2016–2017). The proceeding included an evidentiary hearing, parties' briefs, and oral argument before the BPA Administrator. This ROD addresses the issues raised by parties in this proceeding, as stated in their briefs. For each issue, it describes the parties' and BPA Staff's positions. It then evaluates the positions and presents the Administrator's decision. The ROD also summarizes and responds to participant comments that were submitted during the public comment period, which ended on February 26, 2015.

1.1.1 Procedural History of this Rate Proceeding

1.1.1.1 Issue Workshops

For several months before the release of Staff's Initial Proposal, BPA sponsored a series of workshops on a variety of topics related to its power and transmission ratemaking. BPA designed the workshops so they would allow BPA Staff and interested parties to develop a common understanding of specific topics, generate ideas, and discuss alternative proposals. BPA held seven workshops between January and June 2014 on transmission segmentation issues; five workshops between May and August 2014 on generation inputs issues; eleven workshops between April and September 2014 on additional transmission rates issues; four workshops between July and September 2014 on power rates issues; and one workshop in August 2014 on financial reserves. In addition, BPA held four workshops between August and October 2014 on the Rate Period High Water Mark (RHWM) Process.

Conducting the issue workshops before the development of the Initial Proposal allowed BPA Staff and interested parties to freely exchange ideas and comments relevant to rates issues without the prohibition on *ex parte* communication that takes effect upon publication of the rate proposal in the Federal Register. The *ex parte* prohibition for this rate proceeding went into effect on December 4, 2014, and ends when BPA issues this Final ROD. The Initial Proposal incorporated a number of the ideas and proposals that were discussed in the workshops.

1.1.1.2 BP-16 Rate Proceeding

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(i), requires that BPA's rates be established according to specific procedures that include, among other things, issuance of a notice in the Federal Register

announcing the proposed rates; the opportunity for interested parties to submit written and oral views, data, questions, and arguments; and a decision by the Administrator based on the record. This proceeding is also governed by BPA's rules for general rate proceedings, the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7,611 (1986) (hereinafter, *Procedures*). The *Procedures* implement the section 7(i) requirements.

The BP-16 rate proceeding includes power and transmission rates in a single docket. On December 4, 2014, BPA published a Federal Register notice, "Fiscal Year (FY) 2016–2017 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment," 79 Fed. Reg. 71,984 (2014). On December 5, 2014, BPA held a scheduling conference to discuss a procedural schedule and procedural orders with prospective parties in the case. The formal rate proceeding began with a prehearing conference on December 10, 2014. After the prehearing conference, the Hearing Officer issued orders establishing the schedule for the rate proceeding, special rules of practice, data request procedures, and general acronyms; he also granted petitions to intervene.

BPA Staff's Initial Proposal was supported by Staff's initial studies and written testimony issued on December 10, 2014. Clarification of Staff's Initial Proposal took place on December 17, 2014. The parties filed their direct testimony on February 4, 2015. BPA and all parties waived clarification of the parties' direct testimony. BPA Staff and the parties filed rebuttal testimony on March 16, 2015. Clarification of Staff's rebuttal testimony took place on March 19, 2015.

Because BPA Staff intended to propose significant changes in its rebuttal testimony on four issues, it filed a motion with the Hearing Officer to allow the parties to submit surrebuttal testimony on these issues. The issues were the Montana Intertie rate; the Utility Delivery rate, including segmentation related to the Utility Delivery segment; the use of transmission reserves, including rate schedule changes necessary to implement the proposed changes; and power risk mitigation. The Hearing Officer granted the motion, and the parties filed surrebuttal testimony on March 30, 2015. *See Order Granting BPA's Motion to Amend the Procedural Schedule*, BP-16-HOO-13. BPA and all parties waived clarification of the surrebuttal testimony.

Cross-examination of all parties was scheduled for April 8-9, 2015. Prior to that time, however, all parties waived their opportunity for cross-examination.

The parties filed their initial briefs on May 1, 2015. Oral argument before the Administrator took place on May 8, 2015. The Draft ROD was issued on June 12, 2015. Briefs on exceptions were filed on July 1, 2015.

At times, certain parties to this proceeding consolidated for the purpose of filing testimony or submitting a brief on one or more issues. *See Special Rules of Practice Governing this Proceeding*, BP-16-HOO-02. The rate case clerks assigned each consolidated group of parties (joint party) an alphanumeric designation (*e.g.*, JP01, JP02, JP03). For convenience, a list of the joint parties appears in the list of Party Abbreviations and Joint Party Designation Codes that is included at the beginning of this ROD. *See also Document Numbering System and Pre-Marking of Exhibits and Briefs*, BP-16-HOO-04.

BPA received three written comments during the participant¹ comment period, which began with the publication of the notice in the Federal Register on December 4, 2014, and ended February 26, 2015. Participant comments are part of the record upon which the Administrator bases his decisions; they are summarized and addressed separately in ROD Chapter 5. Participant comments may be viewed at BPA’s Web site under “Public Involvement.”

1.1.1.3 Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Service Rates

Beginning in May 2014, BPA held rate case settlement workshops with the customers on generation inputs issues that form the foundation of most ancillary service and control area service rates. Fisher and Fredrickson, BP-16-E-BPA-12, at 1-2. Over the next six months, BPA and the customers developed a settlement agreement that covers all ancillary and control area service rates except (1) Scheduling, System Control, and Dispatch Service; and (2) Reactive Supply and Voltage Control from Generation Sources Service. Setting aside the Risk Mitigation Tools section of the settlement, which had the potential to adjust the settlement rates, the settlement rates for Regulation and Frequency Response Service, Variable Energy Resource Balancing Service, and Dispatchable Energy Resource Balancing Service are unchanged from the BP-14 rates for those services. *Id.* at 3-4. The settlement rates for Operating Reserves, both Spinning and Supplemental, are 5 percent higher than the BP-14 rates. *Id.* at 4.

The Partial Settlement Agreement set cost allocations from Power Services to Transmission Services for synchronous condensing, generation dropping, redispatch, segmentation of Corps of Engineers and Bureau of Reclamation network and delivery facilities, and station service. These costs are recovered in various transmission rates. *Id.* at 4-5. The settlement agreement also provides for other changes to the rate schedules and specifies the amount of balancing reserve capacity to be provided during the rate period and an acquisition budget for balancing reserve capacity. BPA tendered the Partial Settlement Agreement to the customers on September 19, 2014. Customers were given until September 25, 2014, to indicate their intent to contest the settlement. No customer did so. *Id.* at 2. By the deadline, 29 parties signed or agreed not to contest the settlement agreement. BPA filed the BP-16 generation inputs Partial Settlement Agreement as part of the BP-16 Initial Proposal. *Id.*, Appendix A. On December 16, 2014, the Hearing Officer issued an order requiring that “[a]ny party wishing to object to the Generation Inputs Settlement Agreement must do so no later than 4:30 p.m. PST on Monday, December 22, 2014.” Order Establishing Deadline to Object to the Proposed Generation Inputs Settlement Agreement, BP-16-HOO-07. No party objected. The settlement is further discussed in Chapter 3.0.

¹ For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA’s *Procedures* provide opportunities to participate in the ratemaking process through submission of comments as a “participant.” *See* section 1010.5 of BPA’s *Procedures*. No party may submit comments as a participant, and comments so submitted will not be included in the record. Special Rules of Practice Governing this Proceeding, BP-16-HOO-02.

1.1.1.4 Waiver of Issues by Failure to Raise in Briefs

Pursuant to section 1010.13(b) of the *Procedures*, arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve any matter at issue.

Sections 1010.13(c) and (d) of the *Procedures* set forth the requirements applicable to initial briefs and briefs on exceptions. A party that raised an issue in its initial brief need not reassert that issue in its brief on exceptions in order to avoid waiving the issue; all arguments raised by a party in its initial brief are deemed to have been raised in the party's brief on exceptions. Special Rules of Practice Governing this Proceeding, BP-16-HOO-02, at 5.

1.1.2 Legal Guidelines Governing Establishment of Rates

1.1.2.1 Statutory Guidelines

Section 7(a)(1) of the Northwest Power Act directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839e(a)(1). Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are established.

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that the Secretary of Energy shall transmit and dispose of electric power and energy in such manner as to encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act provides that rate schedules shall be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. *Id.*

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974 (Transmission System Act), 16 U.S.C. § 838, which contains requirements similar to those of the Flood Control Act. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, provides that rates shall be established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay, when due, the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the

Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. § 838h, allows for uniform rates for transmission and for the sale of electric power and specifies that the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing the system.

1.1.2.2 The Broad Ratemaking Discretion Vested in the Administrator

The Administrator has broad discretion to interpret and implement statutory directives applicable to ratemaking. These directives focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pac. Power & Light v. Duncan*, 499 F. Supp. 672 (D. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (“widest possible use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *ElectriCities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit has recognized the Administrator’s ratemaking discretion. *Cent. Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (“Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacifiCorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atl. Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA’s rate determination upheld as a “reasonable decision in light of economic realities”); *Dep’t of Water and Power of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) (“Insofar as agency action is the result of its interpretation of its organic statutes, the agency’s interpretation is to be given great weight”); *Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1211 (9th Cir. 2006) (“[The GRSPs] are entirely bound up with BPA’s rate making responsibilities, and we owe deference to the BPA in that area”). The Supreme Court of the United States has also recognized the Administrator’s ratemaking discretion. *Aluminum Co. of America v. Cent. Lincoln Peoples’ Util. Dist.*, 467 U.S. 380, 389 (1984) (“The Administrator’s interpretation of the Regional Act is to be given great weight.”).

1.1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates

Under the Northwest Power Act, BPA’s rates become effective upon confirmation and approval by the Commission. 16 U.S.C. § 839e(a)(2) & (k). The Commission’s review is appellate in nature, based on the record developed by the Administrator. *U.S. Dep’t of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *U.S. Dep’t of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. § 839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

1.1.3.1 Standard of Commission Review

The Commission reviews BPA rates under the Northwest Power Act to determine whether they (1) are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA's other costs; and (2) are based on BPA's total system costs. With respect to transmission rates, Commission review includes an additional requirement: to ensure that the rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2). See *U.S. Dep't of Energy—Bonneville Power Admin.*, 39 FERC ¶ 61,078, 61,206 (1987). The limited Commission review of rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which is subject to Commission jurisdiction. *Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

1.2 Related Topics and Processes

This section includes discussion of topics and processes separate and distinct from this rate proceeding that provide information and policy context to the proceeding, including program cost estimates developed in the Integrated Program Review (IPR), BPA's Energy Efficiency (EE) program, the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement), and the Rate Period High Water Mark Process. Issues related to those processes are outside the scope of the BP-16 7(i) proceeding. 79 Fed. Reg. 71,986, 71,987 (2014).

1.2.1 Integrated Program Review

Since 1986, in a process separate from its rate proceedings, BPA has conducted a public review of planned spending levels used in the development of rates. The IPR process provides interested parties the opportunity to review and provide comment on all of BPA's expense and capital spending level estimates prior to the use of those estimates in setting rates. The first step in the IPR process, the Capital Investment Review (CIR), focuses on reviewing and discussing draft asset strategies and 10-year capital forecasts. After a January 2014 IPR kickoff meeting, the 2014 CIR was held in February and March 2014. Public comments received during the CIR informed capital cost projections for FY 2016–2017 in the 2014 IPR.

In May 2014 BPA began the IPR's public, program-level review of the planned expenses to be included in setting power and transmission rates in the BP-16 rate proceeding. In May and June 2014, BPA held technical workshops and responded to participants' requests for additional information. The IPR process provided opportunities for BPA and participants to review and discuss power, transmission, and agency services programs and included detailed review of asset strategies and associated program spending levels.

On October 2, 2014, BPA issued the Final Close-Out Report for the IPR, in which BPA responded to participants' comments. In the report, BPA established the program-level cost estimates that are used in the Initial Proposal to establish the power and transmission rates. On January 30, 2015, BPA invited the region to participate in an abbreviated IPR2 public process to discuss proposed adjustments from the 2014 IPR related primarily to energy

efficiency financing options. The process began with a public meeting in Portland on February 24, 2015. The comment period ended on March 13, 2015. On May 1, 2015, BPA issued the IPR2 close-out letter and Final Close-out Report, which detailed BPA’s decision to move the Energy Efficiency program from capital financing to expense in the upcoming rate period, FY 2016–2017. BPA will offset the increase in expense due to this change with reductions in BPA spending levels and debt management actions associated with the refinancing of \$757 million of Energy Northwest bonds. For further information on the IPR and IPR2 processes and outcomes, see the BPA Web site under “Finance & Rates,” “Financial Public Processes,” “Integrated Program Review.”

1.2.2 Energy Efficiency (EE) Program

In their initial briefs, several parties request that BPA conduct a public process to develop a new delivery model for BPA’s energy efficiency programs. In the context of encouraging BPA to enhance the competitiveness of its Priority Firm Power (PF) rates, WPAG recommends that BPA conduct a process during the BP-16 rate period to examine and develop an alternative to BPA’s current delivery model for energy efficiency. WPAG Br., BP-16-B-WG-01, at 3. WPAG requests that if the IPR2 closeout letter does not state that BPA will conduct such a process, “BPA should commit to holding such forums in the Final Record of Decision.” *Id.* Snohomish makes the same request, asking BPA to “initiate stakeholder meetings following issuance of the BP-16 Record of Decision to discuss modernizing BPA’s service delivery and funding mechanisms for conservation.” Snohomish Br., BP-16-B-SN-01, at 13. Snohomish states that the public process should be finalized “ahead of the BP-18 rate proceeding and initial proposal.” *Id.* at 14. JP17 notes that its members, EWEB and Cowlitz, submitted comments in the IPR2 process “arguing that BPA needs to rethink how it encourages and funds energy efficiency” JP17 Br., BP-16-B-JP17-01, at 4. JP17 reiterated in its brief its “recommendation that BPA transition ... to fully expensing for rate purposes its EE expenditure.” *Id.*

Staff did not address this topic in testimony because the development and implementation of BPA’s Energy Efficiency program are outside the scope of the rate proceeding. 79 Fed. Reg. 71,984, 71,986 (Dec. 4, 2014). Nonetheless, BPA understands its customers’ desire to engage with BPA on the EE program. BPA is preparing to conduct additional dialogue with customers, the Council, and constituents about how to support regional energy efficiency achievements as part of a broader discussion on the agency’s long-term cost structure and product delivery models beginning in the fall of 2015. IPR2 Final Close-out Report at 7. WPAG supports BPA’s commitment to these discussions. WPAG Br. Ex., BP-16-R-WG-01, at 3.

1.2.3 2012 Residential Exchange Program Settlement Agreement

On July 26, 2011, the Administrator executed the 2012 REP Settlement, which resolved longstanding litigation over BPA’s implementation of the Residential Exchange Program under section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c). The Administrator’s findings regarding the legal, factual, and policy challenges to the 2012 REP Settlement are thoroughly explained in the REP-12 Record of Decision (REP-12 ROD). The 2012 REP Settlement and the Administrator’s decision in the REP-12 ROD to sign the settlement were upheld by the Ninth

Circuit Court of Appeals in *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013).

1.2.4 Rate Period High Water Mark Process

BPA has established FY 2016–2017 RHWMs for Public customers with Contract High Water Mark (CHWM) contracts. In the RHWM Process, which preceded the BP-16 rate proceeding and concluded in October 2014, BPA established the maximum planned amount of power a customer is eligible to purchase at Tier 1 rates during the rate period, the Above-RHWM Loads for each customer, the System Shaped Load for each customer, the Tier 1 System Firm Critical Output, RHWM Augmentation, the Rate Period Tier 1 System Capability (RT1SC), and the monthly/diurnal shape of RT1SC. The RHWM Process provided customers an opportunity to review, comment, and challenge BPA's RHWM determinations. The RHWMs and related outputs of the RHWM Process are combined with the rate case load forecast to develop billing determinants and for other ratesetting purposes.

1.3 Procedural Issues

1.3.1 Changes to PNRR and CRAC Parameters

Issue 1.3.1.1

Whether the Administrator should make adjustments to Planned Net Revenues for Risk (PNRR) or Cost Recovery Adjustment Clause (CRAC) parameters after litigants have filed their direct and rebuttal cases.

Parties' Positions

JP07 argues that if BPA retains the unilateral right to make any changes to PNRR or CRAC proposals at the end of the rate case, customers could be improperly subject to significant rate increases after all procedure has been exhausted. JP07 Br., BP-16-B-JP07-01, at 7-8.

BPA Staff's Position

BPA must have the ability to adjust its risk mitigation tools for the final rates if necessary to meet BPA's Treasury Payment Probability (TPP) standard; otherwise, the standard would be impossible to implement and could not serve its purpose: to protect BPA's ability to make its Treasury payments in full and on time. Mandell and Lovell, BP-16-E-BPA-33, at 2.

Evaluation of Positions

The BP-16 Initial Proposal incorporated the possibility of many financial outcomes for FY 2015. *Id.* at 1. At the time of the Initial Proposal, nearly a full year of FY 2015 uncertainty remained. *Id.* By the time the final rates are calculated, many of the outcomes that were possible at the time of the Initial Proposal will have become impossible due to actual events in early FY 2015, and other possible outcomes will become more likely than they were at the time of the Initial

Proposal. *Id.* Compared to the Initial Proposal, the distribution of possible FY 2015 outcomes will be much narrower when the final rates are calculated. *Id.* The actual financial outcome for FY 2015 determines the level of BPA reserves available for risk at the start of the FY 2016–2017 rate period. *Id.* at 1-2. Thus, FY 2015 uncertainty is a key input in the calculation of BPA’s rate period TPP and the determination of risk mitigation needs. *Id.* at 2.

As specified in BPA’s Financial Plan, BPA’s TPP standard requires BPA to establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making all of BPA’s scheduled U.S. Treasury payments during each two-year rate period. *Id.* Rates are proposed in the Initial Proposal but established in the final studies. *Id.* Therefore, BPA must have the ability to adjust its risk mitigation tools for the final rates if necessary to meet the TPP standard. *Id.* Otherwise, the standard would be impossible to implement and could not serve its purpose: to protect BPA’s ability to make its Treasury payments in full and on time. *Id.*

JP07 argues that if BPA retains the unilateral right to make any changes to its PNRR or CRAC proposals at the end of the rate case, customers could be improperly subject to significant rate increases after all procedure has been exhausted. JP07 Br., BP-16-B-JP07-01, at 7. JP07 states that “[f]olding the determination of how to respond to a bad financial year ... into the rate case process, and giving the parties a chance to respond to BPA’s proposal, will provide customers with the procedural protections they are entitled to with respect to other rate case issues.” Deen *et al.*, BP-16-E-JP07-01, at 5. Staff supports providing parties the opportunity to review and respond to updates to data that become available during the course of a rate case. Mandell and Lovell, BP-16-E-BPA-33, at 2. However, there are practical problems associated with additional review and comment opportunities that would be undesirable for all litigants, such as (1) the potential for a never-ending cycle of adjustment and review; (2) abandoning any adjustments to the risk package for the final rates; and (3) structuring rates based on a worst-case outcome that would eliminate any possible need for increasing the amount of risk mitigation. *Id.*

As to the first practical problem, at some point the opportunity to review numbers must end so that BPA can finalize its rates. *Id.* Providing additional review and comment opportunities before updates are incorporated into the risk analysis would result in never-ending rounds of updates and reviews, or freezing the current year assumptions in the Initial Proposal. *Id.* Both of these possibilities are untenable. *Id.*

The second practical problem, ignoring actual financial conditions in the year when rates are set (*i.e.*, the year immediately prior to the rate period), is not a sound business practice. *Id.* Furthermore, because BPA’s rates must recover its costs, it is unlikely that such practice would be supported by the Federal Energy Regulatory Commission, which must confirm and approve BPA’s rates before they become effective. *Id.* at 2-3.

As to the third practical problem, BPA would need to inflate risk mitigation in the Initial Proposal so that it would cover the worst-case scenario to ensure that the risk mitigation package would be sufficient to meet the TPP standard in the final rates. *Id.* at 3. The risk mitigation in the final rates could then be reduced from the level in the Initial Proposal. *Id.* However, this method would result in an Initial Proposal that is unnecessarily inflated and provide rate case

parties little insight as to how the final rates would likely turn out. *Id.* None of these alternatives is tenable. *Id.*

As noted previously, ignoring actual financial conditions at the time when rates are set (that is, the months immediately prior to the rate period) is not a sound business practice. *Id.* at 4. This point was emphasized by the Ninth Circuit when it faulted BPA for basing rates on outdated assumptions. *See Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1052 (9th Cir. 2007) (BPA improperly relied on outdated assumptions in establishing rates). Furthermore, if risk mitigation parameters were to be “locked down” in the Initial Proposal (so that those same parameters had to be used for the final rates), on average customers would be more likely to pay higher rates than in the absence of a lockdown. Mandell and Lovell, BP-16-E-BPA-33, at 4. Accepting the JP07 argument could easily be construed to prevent BPA from adjusting its Initial Proposal rates downward, thereby leaving BPA’s final rates at a level higher than risk conditions would indicate are necessary. That result might violate BPA’s statutory requirement to establish the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 839e(a)(1).

In the circumstance that risk mitigation in an Initial Proposal is strengthened (that is, PNRR is added or the CRAC threshold is increased from \$0) to meet the 95 percent TPP standard, it is more likely that the need for such risk mitigation would decrease rather than increase between the Initial Proposal and the final rates. Mandell and Lovell, BP-16-E-BPA-33, at 5. This is because current-year revenue uncertainty becomes smaller between the Initial Proposal and when the final rates are calculated. *Id.* Uncertainty for the year prior to the rate period generally decreases to roughly 20 percent of its Initial Proposal amount (as measured by the distribution’s standard deviation). *Id.* This outcome is due to much of the year having actually occurred and much more being known about streamflow and other factors for the remainder of the year. *Id.* This reduced uncertainty increases TPP, in turn reducing the need for risk mitigation. *Id.* This result does not mean that the need for risk mitigation will always decrease between the Initial Proposal and the final rates—increases or decreases in forecast revenue will also cause TPP to increase or decrease. *Id.* However, increases and decreases in the forecast should be roughly equally likely, leading to no change in TPP on average. *Id.* Because TPP commonly increases from the Initial Proposal to the final rates, adjusting risk mitigation between the Initial Proposal and the final rates benefits BPA’s customers more often than it is adverse to them. *Id.*

JP07 argues that Staff should indicate in its Initial Proposal what modification of the risk parameters would be required to address a specific level of poor financial performance, which would afford customers the opportunity to review Staff’s proposal and respond on the record. Deen *et al.*, BP-16-E-JP07-01, at 4-5. In the instant case, JP07 suggested that Staff should include information on how it would respond to a bad financial year as part of its rebuttal testimony, with brief surrebuttal allowed solely for the purpose of reacting to BPA’s proposal. *Id.* at 5-6. JP07 notes that BPA Staff provided JP07 with a table containing risk mitigation scenarios for FY 2015 revenue changes and the parties had the opportunity to comment on the proposed parameters. JP07 Br., BP-16-B-JP07-01, at 7-8. Staff supported allowing the parties to file surrebuttal testimony on this topic to respond to the noted scenarios, Mandell and Lovell,

BP-16-E-BPA-33, at 8, and surrebuttal was incorporated into the BP-16 procedural schedule. *See* 2016 Rate Adjustment Proceeding Amended Schedule, BP-16-HOO-13.

JP07 argues that, in order to protect BPA's customers, the Administrator should adopt its proposal that a risk mitigation scenario analysis be included in future initial proposals. JP07 Br., BP-16-B-JP07-01, at 8. JP07 acknowledges Staff's willingness to include such information in its initial proposals in future rate cases so that customers will be able to have input regarding the reasonableness of the proposed changes. *Id.* This is a reasonable approach, and BPA will include a risk scenario analysis in BPA's future initial proposals. Mandell and Lovell, BP-16-E-BPA-33, at 8.

JP07 suggests that any changes from the risk mitigation proposal should include public involvement. JP07 Br., BP-16-B-JP07-01, at 8. In the BP-14 rate case, BPA addressed this concern by committing to keep customers and rate case parties informed of expectations for current-year financial conditions and CRAC probabilities. BP-14 Administrator's Final Record of Decision (BP-14 ROD), BP-14-A-03, at 29. BPA also committed that, in the event financial conditions worsen so that the need to adjust risk mitigation parameters appears likely, Staff will hold meetings with customers to discuss options. *Id.* BPA prefers to make adjustments to risk mitigation parameters for the final rates, when necessary, with the input of customers. Mandell and Lovell, BP-16-E-BPA-33, at 4. BPA will commit to continue to keep parties informed of financial conditions as the year progresses, including updated CRAC probabilities and the likelihood of needing PNR. In this proceeding, Staff supports meeting with parties in the event that financial conditions deteriorate in such a way that adjustment of risk mitigation parameters to meet the TPP standard appears likely. *Id.* Specifically, financial updates were provided to parties during BPA's second-quarter financial review process. *Id.* If a need to adjust risk mitigation parameters had appeared likely at that time, or if the situation had changed between the second-quarter review and the final studies, Staff would have held a meeting with parties to discuss risk mitigation adjustment options. *Id.* This approach allows Staff to provide meaningful risk mitigation options to parties and to receive feedback in a timely fashion for consideration by the Administrator in his final rate decisions. However, because BPA has not needed any changes to its BP-16 risk mitigation package, such a meeting is unnecessary.

Adding PNR or changing CRAC parameters is not an exercise of unlimited discretion. There are established guidelines that govern when enhanced risk mitigation would be included in rates—that is, when the TPP is not otherwise being achieved. Nevertheless, in future power rate adjustment proceedings, to the maximum extent practicable, BPA will keep parties informed of any changes to the risk mitigation package from the Initial Proposal and provide an opportunity for parties to respond on the record. However, because there may be rare occasions when the need for enhanced risk mitigation arises so late in the ratesetting process as to render the consideration of feedback infeasible, BPA must reserve as a backstop the right to incorporate the latest information available to strengthen the risk mitigation provisions in final rates at the last moment.

Decision

Because BPA is not proposing any changes in PNRR or CRAC parameters from the Initial Proposal, this issue is moot. Nevertheless, BPA will include a risk mitigation scenario analysis in BPA's future power rate initial proposals. To the maximum extent practicable, BPA will also ensure that parties will be informed of changes to the power risk mitigation package so they will be able to respond to such proposed changes on the record.

2.0 POWER RATES AND POLICIES

2.1 Proposed Power Rate Increase

Issue 2.1.1

Whether BPA should mitigate the proposed power rate increase to make its Priority Firm Power rates more competitive.

Parties' Positions

ICNU states that BPA's PF rates "have not been competitive with market prices for some time." ICNU Br., BP-16-B-IN-01, at 2-3. ICNU states that BPA should cut costs in the long term and "should adopt adjustments, such as those offered by JP07, that will reduce rates in the interim." *Id.* at 3.

WPAG states that BPA's power "is losing its price competitiveness compared to other power supply options." WPAG Br., BP-16-B-WG-01, at 2. WPAG cites "BPA's overall unyielding cost structure" and proposes that "BPA work with customers to begin a holistic review of its cost and rate structures" with the goal of "stable low cost-based power rates." *Id.* at 2-3. WPAG adds that BPA should revisit its revenue requirement and rate decisions in the Final ROD to further mitigate the proposed rate increase. WPAG Br. Ex., BP-16-R-WG-01, at 2-3.

JP07 suggests four "measures ... [that] will support the health of the regional economy and move BPA's rates toward a sustainable level that would be closer to the prices available in the market." JP07 Br., BP-16-B-JP07-01, at 1. JP07 adds that "[t]he measures taken during the Integrated Program Review processes were helpful, but not sufficient given the size of the BPA's proposed rate increase and its impact on customers." JP07 Br. Ex., BP-16-R-JP07-01, at 4.

BPA Staff's Position

Staff does not address this issue in testimony.

Evaluation of Positions

As stated in the Federal Register notice, BPA's spending levels for investments and expenses are not determined or subject to review in rate proceedings. 79 Fed. Reg. 71,984, 71,986 (Dec. 4, 2014). Therefore, the level of BPA's costs, which is determined in the IPR process, is not a rate case issue.

However, three parties—ICNU, which represents industrial consumers in the Northwest; WPAG, which represents some of BPA's public utility customers; and JP07, made up of ICNU and PPC (which represents most of BPA's public utility customers)—address BPA's rate increase and its effect on BPA's competitiveness. ICNU Br., BP-16-B-IN-01, at 2-3; WPAG Br., BP-16-B-WG-01, at 2; JP07 Br., BP-16-B-JP07-01, at 1; JP07 Br. Ex., BP-16-R-JP07-01, at 2-4. All are concerned that BPA's utility customers and their industrial consumers may have to pay more

than they would have to pay other suppliers based on BPA's last two rate increases and the current proposed increase.

Early in the Integrated Program Review process, BPA held a meeting in which utility general managers were asked about the issues and economic challenges they face in their service territories and the impacts BPA's rate decisions have on their customers. In response to their comments, BPA worked with its customers and the interested public to reduce the level of the expected power rate increase. IPR Close-out Letter at 1; *see* ROD § 1.2.1. Even with the cost increases needed to protect the long-term asset value of the aging FCRPS hydropower resources, BPA held the program and internal funding levels established in the IPR to an overall increase that is below the level of inflation. BPA places a high priority on carefully managing its costs during both the short- and long-term time horizons.

ICNU and JP07 note that BPA has the statutory obligation to set rates with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. ICNU Br., BP-16-B-IN-01, at 2; JP07 Br., BP-16-B-JP07-01, at 2. The parties focus on the phrase "lowest possible rates," but of course this obligation must be balanced with BPA's other statutory obligations. For example, in addition to the phrase "lowest possible rates," the same sentence of the Flood Control Act and the Transmission System Act includes the phrase "consistent with sound business principles." 16 U.S.C. § 825s; 16 U.S.C. § 838g. Section 5 of the Flood Control Act also provides that rate schedules shall be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years.

After the BP-16 rate case had begun, BPA held the IPR2 process. *See* ROD § 1.2.1. The most significant outcome of IPR2 was BPA's decision to move the funding of the Energy Efficiency program from capital to expense in the FY 2016–2017 rate period. Doing so will reduce long-term costs and power rates by avoiding an estimated \$1.3 billion in additional debt plus the associated debt service costs to fund conservation programs through 2028 while maintaining BPA's strong commitment to energy efficiency. Further, to mitigate the rate impact of transitioning EE from capital to expense in one rate period, BPA decided in IPR2 to offset this impact through a combination of additional cost reductions (\$20 million per year average) and the adoption of available debt management actions.

BPA understands that, as the parties and the IPR2 closeout letter note, BPA is facing significant pressures on its long-term cost structure. In addition to the effect of low natural gas prices on wholesale electricity prices, the cost of maintaining aging Federal assets, and significant ongoing energy industry changes, BPA's total outstanding debt and related debt service costs continue to increase. Moving the EE capital program to expense reduces BPA's debt and related debt service costs, providing a significant step toward achieving the goals of long-term cost competitiveness and financial sustainability.

With an eye to BPA being the low-cost energy provider of choice when new contracts are offered in 2028, BPA is making its long-term cost structure and product delivery model a high-

priority focus. The decisions in this document have been made in light of this longer-term focus in addition to the near-term concerns about the rate increase. See Administrator’s Preface to this ROD. WPAG states that it is “heartened” by BPA’s commitment “to engage the region in discussions regarding BPA’s long-term cost structure, financial health and program delivery models.” WPAG Br. Ex., BP-16-R-WG-01, at 3.

While BPA is mindful of the impact of the level of its rates on the regional economy, BPA is a self-financing agency and is required by law to set its rates to recover its costs. As WPAG states, many of the drivers for the rate increase involve costs that are beyond the direct control of BPA. WPAG Br., BP-16-B-WG-01, at 2. It is also important to note that BPA has varied and often competing responsibilities. These include, but are not limited to, implementing the Northwest Power Act and BPA’s other statutes to encourage conservation and energy efficiency; facilitating the development of renewable resources within the region; protecting fish and wildlife impacted by the FCRPS; and ensuring that the region has an adequate, efficient, economical, and reliable power supply. The Northwest Power Act requires that “the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources ... including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System.” 16 U.S.C. § 839(4). BPA must strike a balance between fulfilling its multiple obligations and keeping its rates as low as possible consistent with sound business principles. The Initial Proposal struck the appropriate balance with information available at that time, and the final rates do the same as they incorporate the results of the IPR2 process and the latest financial information available.

Decision

BPA has mitigated the proposed power rate increase to the extent reasonably possible to ensure that the agency’s costs are the lowest they can be while meeting all of BPA’s responsibilities as mandated by law. BPA will continue working with customers and other stakeholders to achieve the goal of long-term competitiveness and financial sustainability.

2.2 Loads and Resources

The Power Loads and Resources Study, BP-16-FS-BPA-03, contains the load and resource data used to develop BPA’s wholesale power rates for FY 2016–2017. Documentation supporting the results of the Power Loads and Resources Study is presented in the Power Loads and Resources Study Documentation, BP-16-FS-BPA-03A. The Power Loads and Resources Study is also described in the direct testimony of Miskey *et al.*, BP-16-E-BPA-18.

The Power Loads and Resources Study and supporting documentation have two primary purposes: (1) to determine BPA’s load and resource balance (load-resource balance); and (2) to calculate various inputs that are used in other studies and calculations within the rate case. The purpose of BPA’s load-resource balance analysis is to determine whether BPA’s resources meet, are less than, or are greater than BPA’s load and obligations for the rate period, FY 2016–2017. If BPA’s resources are less than the amount of load forecast for the rate period, system augmentation is required to achieve load-resource balance.

The Power Loads and Resources Study includes three main components: (1) load data, including a forecast of the Federal system load and contract obligations; (2) resource data, including Federal system resource and contract purchase estimates, total Pacific Northwest regional hydro resource estimates, and the estimated amount of power purchases that are eligible for section 4(h)(10)(C) credits; and (3) the Federal system load-resource balance, which compares Federal system sales, loads, and contract obligations to the Federal system generating resources and contract purchases.

The Power Loads and Resources Study provides inputs to various other studies and calculations in the ratemaking process: (1) the Power Rates Study, BP-16-FS-BPA-01; (2) the Power Revenue Requirement Study, BP-16-FS-BPA-02; and (3) the Power Risk and Market Price Study, BP-16-FS-BPA-04.

No party raised issues related to BPA's forecast of loads and resources for the BP-16 rate period.

2.3 Power Revenue Requirement

The Power Revenue Requirement Study, BP-16-FS-BPA-02, determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including but not limited to:

- repayment of the Federal investment in hydro generation, fish and wildlife recovery, and conservation
- Federal agencies' operations and maintenance expenses allocated to power
- capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest
- other purchase power expenses such as system augmentation and balancing power purchases
- power marketing expenses
- costs of transmission facilities needed to integrate Federal generation
- costs for purchasing other transmission services

BPA develops its revenue requirement in conformance with the financial, accounting, and ratemaking requirements of DOE Order RA 6120.2. BPA determines the revenue requirement separately for generation and transmission. *U.S. Dep't of Energy—Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The revenue requirement is developed using a cost accounting analysis comprised of the following three components:

1. Repayment studies to determine a schedule of amortization payments and to forecast annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment

studies are conducted for each year of the two-year rate test period and extend over a 50-year repayment period.

2. For each year of the rate test period, operating expenses and the minimum required net revenues that may be added to the revenue requirement to ensure that there is adequate cash flow to repay the Federal investment.
3. Annual Planned Net Revenues for Risk, if any, based on the risks identified and quantified, the Treasury Payment Probability standard, and other risk mitigation tools.

With these three parts, the revenue requirement is set at the lowest revenue level necessary to fulfill cost recovery requirements and objectives.

Order RA 6120.2 requires that BPA demonstrate the adequacy of current and proposed rates. The current revenue test determines whether revenues projected from current rates meet cost recovery requirements for the rate period and over the ensuing 50-year repayment period. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test period and over the ensuing 50-year repayment period. The revised revenue test demonstrates that revenues from proposed power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment period. Power Revenue Requirement Study, BP-16-FS-BPA-02, § 3.3. The risks are quantified and analyzed, and risk mitigation measures are incorporated into rates as needed to achieve at least a 95 percent probability that planned payments to Treasury are made on time and in full over the two-year rate period.

No party raised issues related to BPA's power revenue requirement for the BP-16 rate period.

2.4 Power Risk and Market Price

The Power Risk and Market Price Study, BP-16-FS-BPA-04, identifies, models, and analyzes the impacts that key risks and risk mitigation tools have on Power Services' net revenue and cash flow. It also demonstrates that the power rates and risk mitigation tools working together meet BPA's standard for financial risk tolerance—the Treasury Payment Probability standard. This study presents BPA's natural gas price forecast, electricity market price forecast, and quantitative and qualitative analysis of risks to achieving Power Services' net revenue. It also presents tools for mitigating risk and establishes the adequacy of those tools for meeting BPA's 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. 1993 Final ROD, WP-93-A-02, at 72-73. 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 entire rate period rather than the probability for a single year. The Financial Plan was updated July 31, 2008, and remains in

effect. The original and updated financial plans are available at <http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx>.

By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. 16 U.S.C. § 839e(a)(2)(A). Therefore, TPP is a prospective measure of BPA's overall ability to meet its financial obligations. The following policy objectives guide the development of the risk mitigation package:

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

It is important to understand that 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.

A procedural issue was raised regarding BPA's risk mitigation proposal for the BP-16 rate period; this issue is addressed in section 1.3. An issue related to the secondary revenue forecast portion of BPA's Power Risk and Market Price Study appears below.

Issue 2.4.1

Whether BPA should reflect secondary energy sales made at extra-regional points of delivery in BPA's forecast of secondary revenue.

Parties' Positions

JP07 notes that BPA has historically marketed secondary energy at points of delivery contiguous to the California Independent System Operator (ISO) but does not model sales at these same points of delivery in its forecast of secondary revenue. JP07 Br., BP-16-B-JP07-01, at 2; *see* JP07 Br. Ex., BP-16-R-JP07-01, at 4. JP07 states that during FY 2014, BPA delivered approximately 26 percent of its surplus power through off-system sales to southern markets. JP07 Br., BP-16-B-JP07-01, at 2. JP07 notes that BPA's sales within the Northwest that year

had an average price of \$24.97 per megawatt-hour, but BPA received an average weighted price of \$34.43 for southern sales delivered outside the region. *Id.* Therefore, JP07 argues, BPA should increase its forecast of secondary revenue for the upcoming rate period by \$25.4 million to account for the incremental value of marketing energy at southern points of delivery. JP07 Br., BP-16-B-JP07-01, at 3; JP07 Br. Ex., BP-16-R-JP07-01, at 4-6.

JP07 also states that BPA holds firm transmission rights on the Southern Intertie, for which BPA pays \$14.7 million per year, which enable it to market power to these points of delivery. *Id.* at 5. JP07 argues that it is not reasonable to pay for these rights if BPA does not intend to use them to market energy. *Id.* JP07 suggests that, at a minimum, BPA should establish a credit of \$14.7 million to ensure that the aforementioned firm transmission rights do not represent a net cost to Power customers. *Id.* at 6.

JP07 supports the Administrator's preliminary decision to include an ad hoc upward adjustment to the secondary revenue credit used to calculate the BP-16 power rates. JP07 Br. Ex., BP-16-R-JP07-01, at 2. JP07 also supports the Administrator's desire to convene an informal public process to examine BPA's forecasting of secondary energy sales and evaluate how future rates might include appropriate adjustments. *Id.*

BPA Staff's Position

The forecast of secondary revenue should not be adjusted to account for potential extra-regional sales. Williams, BP-16-E-BPA-34, at 3. Currently, BPA does not have contracts in place to market energy into California during the upcoming rate period. *Id.* at 2. Also, changes to regulations governing energy sales in California may limit extra-regional sales. *Id.* As such, it is difficult for BPA to forecast the availability of those markets for purposes of selling its surplus energy. Further, JP07's proposed \$25.4 million or \$14.7 million adjustments are not reasonable proxies for the potential value of extra-regional energy sales. *Id.* at 3.

Staff supports conducting an informal public process before the BP-18 rate case to examine BPA's forecast of secondary energy sales. *Id.* at 4.

Evaluation of Positions

BPA's secondary revenue forecast uses monthly Mid-Columbia prices from AURORA[®] to value secondary energy sales. Williams, BP-16-E-BPA-34, at 1, *citing* Power Rates Study, BP-16-E-BPA-1, at 35. The study assumes that secondary revenue sales are made at the Mid-Columbia trading hub for pricing purposes, and those sales are valued using an average hourly spot-market price. *Id.*, *citing* Hammer and Williams, BP-16-E-BPA-19, at 1. This approach is reasonable because Mid-Columbia is a liquid trading hub and represents the bulk of BPA's marketing activity. *Id.* at 1-2. Each year, variations in hydrological conditions, load, natural gas prices, and other factors result in BPA's secondary energy being marketed in different volumes and at different points of delivery. *Id.* at 2.

JP07 notes that during FY 2014, BPA delivered approximately 26 percent of its surplus power to southern markets, primarily at the California-Oregon border (COB) and the Nevada-Oregon

border (NOB). JP07 Br., BP-16-B-JP07-01, at 2; JP07 Br. Ex., BP-16-R-JP07-01, at 4. COB and NOB are market nodes for selling into the California market. JP07 states that BPA's sales within the Northwest that year had an average price of \$24.97 per megawatt-hour, but BPA received an average weighted price of \$34.43 for southern sales delivered outside the region. JP07 Br., BP-16-B-JP07-01, at 2. JP07 notes that BPA's proposed rates are calculated with the assumption that no sales will be made outside the region because Staff assigned Mid-Columbia prices to all off-system sales. JP07 Br., BP-16-B-JP07-01, at 3; JP07 Br. Ex., BP-16-R-JP07-01, at 4. JP07 claims that Staff offers no support for the proposition that BPA will make all sales at Mid-Columbia. JP07 Br., BP-16-B-JP07-01, at 3.

JP07's argument omits a nuance in Staff's position. Staff does not simply assume that BPA will make all sales at Mid-Columbia; rather, Staff recognizes that BPA may make some extra-regional secondary sales during the rate period and, if and when such sales are made, they may or may not be made at a premium to forecast Mid-Columbia prices. Williams, BP-16-E-BPA-34, at 2. However, forecasting the amounts and prices for such sales is problematic due to the many factors that affect the amounts and delivery points for secondary energy sales. *Id.* Because of the difficulty in developing an accurate forecast, BPA uses Mid-Columbia prices as a proxy for extra-regional sales prices because Mid-Columbia is a liquid trading hub, represents the bulk of BPA's marketing activity, and reflects the inherent optimism in relying on forecasts from a computer model with "perfect" market knowledge. *Id.* at 1-2. This is not the same as believing that all extra-regional power sales will actually go through Mid-Columbia. Forecasts of secondary energy prices, by their very nature, are highly variable expectations of future events. Attempting to incorporate the effects of marketing power into different markets adds a measure of precision that has not been demonstrated to be necessary based on the rate case record.

JP07 assumes that the amounts of power sales and the prices of such sales during a single historical year can be used to determine power sales in the two years of the future rate period. JP07 Br., BP-16-B-JP07-01, at 3. Using only a single historical year of data, JP07 argues that the Administrator should increase the secondary revenue forecast by \$25.4 million. *Id.* JP07 assumes that 24 percent of BPA's FY 2014 historical secondary sales will be made at a 38 percent premium over Mid-Columbia prices, then discounts this adjustment by 20 percent to reduce the risk of under-collection if variations in market conditions during the BP-16 rate period result in fewer available transactions in extra-regional markets. *Id.*

As logic suggests, and as the record shows, it is wrong to assume that data from a single historical year provides a reasonable estimate of what will occur in a future two-year period. Williams, BP-16-E-BPA-34, at 3. JP07's data is based on a single year, 2014, but the prices obtained at regional and extra-regional points of delivery will vary each year based on numerous different conditions. *Id.* Indeed, there is no indication that conditions in the upcoming rate period will be similar to those during FY 2014, owing to a number of factors. *Id.* First, natural gas prices are expected to be different. *Id.*, citing Power Risk and Market Price Study, BP-16-E-BPA-04, at 19-23. Hydrological conditions in both the Pacific Northwest and California will be different. *Id.* at 3. Loads will be different, and the rapid growth of renewable energy in California will have a substantial impact on regional markets. *Id.* In fact, JP07 apparently

recognizes that conditions in the upcoming rate period could be different from those during FY 2014 by discounting its proposed increase in the forecast of secondary revenues to reduce any risk of under-recovery in the case that FY 2014 results vary from conditions in the BP-16 rate period. JP07 Br., BP-16-B-JP07-01, at 3; Deen *et al.*, BP-16-E-JP07-01, at 8. Historical pricing data for a single year is not a sufficient basis upon which to forecast future secondary prices for the FY 2016–2017 rate period. Williams, BP-16-E-BPA-34, at 3.

Furthermore, BPA’s secondary revenues have never been forecast based on historical sales, but rather based on an extensive analysis of forecast conditions. JP07’s estimate of \$25.4 million does not reflect an appropriate difference between the current secondary revenue forecast and a more reasonable forecast. *Id.* By virtue of the fact that it is calculated retrospectively, that estimate is a statistically perilous number that is not the product of any analysis regarding expected conditions during FY 2016–2017. *Id.*

JP07 is troubled by BPA’s statement that “[a]ttempting to incorporate the effects of marketing power into different markets adds a measure of precision *that has not been demonstrated to be necessary based on the rate case record.*” JP07 Br. Ex., BP-16-R-JP07-01, at 5 (emphasis by JP07), *citing* Draft ROD, BP-16-A-01, at 20. JP07 states that it presented substantial evidence that BPA’s current methodology does not appropriately account for the contribution of secondary energy sales made outside the region to BPA’s overall net secondary revenues. *Id.* Although JP07 presented evidence to demonstrate its claim, BPA disagrees that JP07 accomplished its goal. This is because although Staff’s initial forecast assumed that Mid-C prices were paid for BPA’s secondary sales and BPA did not assume different prices for extraregional sales, this does not mean that BPA’s forecast is therefore flawed. JP07’s argument for adding \$25.4 million to the forecast is based solely on the differential between actual prices at Mid-Columbia and southern markets. JP07 did not examine how BPA’s forecast of market prices and revenues for FY 2014 compares to actual results. BPA’s net secondary revenue (secondary sales revenues minus certain purchased power expenses) was \$31 million greater than the BP-14 rate case forecast. *See* November 2014 Quarterly Business Review at 18 (Nov. 4, 2014), *available at* <http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/Pages/fy2014.aspx>. This extra revenue was primarily attributable to 3 million acre-feet of water above forecast. *Id.* There is no information in the rate case record to assess what role the extra-regional sales played in the FY 2014 secondary revenue variance because there is no examination of price variation between the BP-14 rate case price forecast and actual results. JP07 presented only one piece of a more complex differential analysis. Nevertheless, BPA is always interested in ensuring that its forecasts are accurate. Although BPA disagrees with JP07’s analysis, BPA will investigate whether there is an alternative manner of incorporating extra-regional sales into BPA’s secondary revenue forecast that would provide greater precision to the forecast.

JP07 argues that when detailed projections cannot be made, it is standard practice throughout the utility industry to use, or begin with, the most recent historical test year because that information will most accurately represent the revenues and costs that can be expected in the rate period. JP07 Br., BP-16-B-JP07-01, at 4. JP07, however, cites no evidence in the record to support this assertion. Furthermore, BPA’s extra-regional secondary sales vary greatly based on hydrological conditions, load, natural gas prices, and other factors. Williams, BP-16-E-BPA-34, at 3.

Secondary sales are not like many items from a utility's historical test year, which may be relatively stable from year to year.

JP07 claims that BPA's rationale for using Mid-Columbia is only that forecasting sales to COB and NOB is "difficult." JP07 Br., BP-16-B-JP07-01, at 4. To the contrary, however, Staff explained *why* it is difficult to forecast extra-regional sales to COB and NOB. Williams, BP-16-E-BPA-34, at 2. Furthermore, California state laws may change, or intermediaries for some transactions may not be available, either of which would compromise BPA's ability to deliver to COB or NOB. *Id.* at 2. Also, variations in hydrological conditions, load, natural gas prices, and other factors result in BPA's secondary energy being marketed in different volumes and at different prices. *Id.*

JP07 states that the Administrator must take steps to mitigate the proposed power rate increase in BP-16. JP07 Br. Ex., BP-16-R-JP07-01, at 4. JP07 suggests that by adopting the maximum possible upward adjustment to the secondary revenue credit used to calculate the BP-16 power rates, as proposed by JP07, the Administrator will satisfy his obligation to offer consumers the lowest possible rates consistent with sound business principles and move BPA's rates toward a sustainable level that would be closer to the prices available in the market. *Id.* BPA understands JP07's interest in having BPA establish the lowest possible rates, but, as JP07 acknowledges, such rates must be consistent with sound business principles. BPA is a self-financing agency and is required by law to set its rates to recover its costs. Many of the drivers for the current rate increase involve costs and revenues that are beyond BPA's direct control. Also, BPA has varied and often competing responsibilities. *See* § 2.1 above. Although BPA appreciates JP07's proposal to increase BPA's secondary revenue forecast by \$25.4 million, such an assumption would require BPA to assume too much risk in its BP-16 rates. As noted above, JP07 first raised an issue regarding BPA's financial risk when it proposed that its initial calculation of BPA's extraregional secondary revenue should be reduced by 20 percent to "reduce any risk of under-recovery in the case that FY 2014 results vary from conditions in the BP-16 rate period." Deen *et al.*, BP-16-E-JP07-01, at 8. JP07's analysis looks at conditions for only one year of secondary sales, 2014, which may or may not recur. BPA does not know whether 2014 would be representative of BPA's sales in the prospective rate period. To the extent that the forecast includes additional revenue from extraregional sales that fails to materialize, BPA's rates would be less likely to recover BPA's costs.

JP07 recognizes the desirability of a more refined approach to projecting off-system sales revenues and does not assume that basing future secondary revenues on the amounts and prices of power sales during a single historical year is an optimal method. JP07 Br. Ex., BP-16-R-JP07-01, at 5. Rather, JP07 submits that actual data from 2014 represents BPA's trading practices during the most recent available time period and is indicative of market conditions that can be anticipated during the upcoming rate period, and thus is the best evidence in the record to guide the Administrator's proposed ad hoc adjustment for BP-16 rates. *Id.* Although JP07 has presented one approach for forecasting BPA's secondary revenues, BPA disagrees that it is the best evidence on which to base an ad hoc adjustment. As noted previously, BPA's trading practices in 2014, regardless of how recent, do not necessarily have any correlation to BPA's secondary revenues during the BP-16 rate period. Instead, the analysis supporting BPA's Initial

Proposal secondary revenue forecast is the strongest evidence upon which to base BPA's BP-16 secondary revenue forecast. Although BPA will rely on its initial proposal secondary revenue forecast, as noted above, BPA will make an ad hoc adjustment of \$10 million to increase the forecast to account for some amount of extra-regional marketing pending a more complete examination prior to the BP-18 proceeding. This amount is a reasonable adjustment to BPA's forecast because it balances BPA's desire to keep rates as low as prudently possible with the amount of risk that is being undertaken in setting rate levels that may prove to be too low. In arriving at the \$10 million, BPA has weighed the risk against the final level of rate increase and considers that this amount strikes the best balance between setting the lowest possible rates and being consistent with sound business principles.

As noted above, Staff notes that JP07's use of only one year of historical data to develop its proposed adjustment would not produce an accurate projection of BPA's likely off-system sales, given a number of variables affecting sale amounts and prices during each year. Williams, BP-16-E-BPA-34, at 3. JP07 claims Staff's argument is disingenuous because JP07 requested multiple years' data from BPA in order to develop a more refined projection, and BPA Staff refused to provide the data on the basis that the request was burdensome. JP07 Br., BP-16-B-JP07-01, at 4, *citing* Deen *et al.*, BP-16-E-JP07-01, at Att. A. This argument is not persuasive. Although JP07 requested multiple years' data from BPA, JP07 fails to describe the enormity of the data JP07 requested. JP07's data request asked for "documentation of all of BPA's secondary/surplus energy sales for the period of FY 2010 through FY 2014 in Microsoft Excel format. Please include the counterparty, duration, amount of power sold, price, point of delivery, and product type." Deen *et al.*, BP-16-E-JP07-01, at Att. A. In response, BPA stated:

BPA objects to this data request on the following grounds: 1. The request does not identify any specific portion of the Study to which it is directed. Instead, the request cited the entire Power Risk and Market Price Study. Citation to an entire study does not comply with Attachment A of BP-16-HOO-1, Order on Data Requests, under which parties must identify the page numbers and line numbers that are relevant to the request. 2. The requested information is not available in the form requested. Under the Rules of Procedure Governing Rate Hearings, §1010.8(b), "no party shall be required to perform any new study or to run any analysis or computer program." Given the volume of data and the requested format, the data request is tantamount to a request for a new study, analysis, or program. 3. Given the requirements of the request and the quantity of data involved, responding to the request would be unduly burdensome. See Rules of Procedure Governing Rate Hearings, §1010.8(b).

Id. Notably, JP07 did not contest or appeal BPA's response to its data request, although it could have done so. Furthermore, the objection upon which BPA's data response relied is a well-established standard in administrative and judicial practice, and is included in BPA's hearing procedures. BPA's procedures provide that a party may not request material that is "unduly burdensome to produce." Rules of Procedure Governing Rate Hearings, § 1010.8(b). When BPA established this standard, JP07 did not object; nor was the standard challenged in

court. BPA's decision not to produce all the data requested by JP07 is consistent with BPA's Rules of Procedure and as such does not support JP07's case or harm Staff's case.

JP07 also argues that no evidence has been presented to demonstrate that multiple years' results would produce results inconsistent with JP07's conclusions. JP07 Br., BP-16-B-JP07-01, at 4. This argument reverses traditional evidentiary standards. The burden of proof is upon the party seeking to establish a fact. The burden is not on BPA to establish facts supporting JP07's case. The record contains no evidence that multiple years' data would have produced results consistent with JP07's conclusions. JP07 also states that the data it used does not rely upon a small number of sales, but on over 49,000 transactions. *Id.* at 4-5. This statement proves the burdensome nature of JP07's data request, which asked for *five years* of such data. In any case, for the reasons stated above, the number of transactions in a single historical year, regardless of whether they are many or few, cannot establish a reliable forecast for a prospective two-year rate period. Williams, BP-16-E-BPA-34, at 3. This is especially true when the southern markets are conducted under an ever-changing set of rules that were not necessarily in place during the recent past.

JP07 argues that if the Administrator chooses to set rates that assume all off-system sales will be made at Mid-Columbia, there is no basis for requiring power customers to include \$14.7 million in transmission purchases in rates. JP07 Br., BP-16-B-JP07-01, at 5. This argument hinges on JP07's assertion that using forecasts of Mid-Columbia prices in setting rates is tantamount to restricting BPA from making extra-regional sales during the rate period. To the contrary, however, and as noted below, it is possible that BPA will make extra-regional secondary sales. If BPA did not make transmission purchases, BPA's ability to sell power outside the region would be extremely limited. This is a logical basis for acquiring transmission rights. JP07 also claims that Staff does not provide an alternate use for such transmission rights. JP07 Br., BP-16-B-JP07-01, at 5. Again, contrary to JP07's claims, Staff addresses alternative uses of transmission rights in its rebuttal testimony. Staff notes that transmission capacity on the Southern Intertie is not a net cost. Williams, BP-16-E-BPA-34, at 4. Staff established that it represents an option value for sales and purchases made extra-regionally and may go unused, be re-sold, or be used for other BPA transactions. *Id.*

JP07 argues that it makes no business sense for BPA to purchase long-term firm transmission rights to another market if BPA does not intend to monetize the transmission by making sales at some level greater than zero into that market. JP07 Br., BP-16-B-JP07-01, at 5. However, BPA does not know the future. It is likely that *some* unidentified amount of extra-regional sales will be made, but this amount is difficult to identify. *See* Williams, BP-16-E-BPA-34, at 2. Because of the possibility of extra-regional sales, it is a prudent business practice to acquire transmission rights to facilitate such possible sales. As noted above, absent securing transmission rights, BPA's sales would be limited. JP07 also states that no reservations of long-term firm transmission are necessary to reach California markets if a specific level of sales cannot be projected because short-term rights are available and flow ahead of many long-term transmission reservations. JP07 Br., BP-16-B-JP07-01, at 5-6. Although short-term rights might be available, relying on them would permit fewer sales than if long-term firm transmission rights were also

available. Also, assuming short-term sales will be made does not help to establish the amount of extra-regional sales that may be made or the prices of such sales.

JP07 argues that if BPA assumes all off-system sales will be made at Mid-Columbia, there is no sound business reason to include \$14.7 million in firm transmission rights in the power revenue requirement, and these costs should not be charged to power customers. *Id.* at 6. JP07 argues that, at a minimum, BPA should assume that it will be able to at least recover the \$14.7 million through economic secondary energy sales or resale of that transmission capacity. *Id.* First, this argument fails because BPA does not simply assume all off-system sales will be made at Mid-Columbia. BPA uses the forecast of Mid-Columbia prices to represent the expected price received from all sales, no matter in which market those sales might occur. Also, as noted previously, even though BPA's forecast of secondary sales assumes such sales will occur at Mid-Columbia prices, it is prudent for BPA to acquire transmission rights to enable possible extra-regional sales during the rate period. The cost of transmission rights, however, is not a forecast of BPA's secondary revenue. The use of \$14.7 million represents an arbitrary valuation of an amount of secondary marketing that has not been forecast. Williams, BP-16-E-BPA-34, at 4.

Staff recognizes the difficulty of forecasting secondary sales outside the region and has offered to work with customers outside of the rate case to examine modeling approaches to address the value of extra-regional secondary sales for the BP-18 proceeding. *Id.* JP07 states that it would support and help develop a method for refining off-system sales projections. JP07 Br., BP-16-B-JP07-01, at 5; JP07 Br. Ex., BP-16-R-JP07-01, at 2. Staff recommends that the Administrator convene an informal process with interested parties to try to achieve this goal after the BP-16 rate case and before the BP-18 rate case. Williams, BP-16-E-BPA-34, at 4. However, such an examination should not be limited solely to prices received from different markets, but whether the secondary revenue credit included in ratesetting reasonably accounts for all expected secondary revenues. Secondary revenue, not just prices, is the most important metric in judging the accuracy of BPA's forecasts.

Although the foregoing discussion in this section has been critical of JP07's proposed *methodology* for determining secondary revenue, JP07's *concept* of reviewing BPA's prospective extra-regional sales as part of determining secondary revenue is worthy of consideration. However, BPA is not entirely convinced that JP07's proposal to discount FY 2014 California revenues by 20 percent is necessarily the appropriate risk adjustment. Until BPA completes its examination of modeling approaches to address the value of extra-regional secondary sales for the BP-18 proceeding, BPA will include an ad hoc upward adjustment to the secondary revenue credit used to calculate the BP-16 power rates that incorporates a risk adjustment BPA considers more reflective of the value of these sales. This is a less-than-desirable approach because it does not account for how price differentials among the various markets will respond to variations in water supply, weather, economic conditions, fuel prices, and the availability of other generation. BPA will make this ad hoc adjustment for BP-16 rates only; the examination of BPA's secondary market forecasts will inform if and how future rates may include any appropriate adjustments.

JP07 claims that BPA offers no justification or alternatives for its conclusion that JP07's proposed 20 percent downward adjustment to actual 2014 secondary sales levels is not necessarily the appropriate risk adjustment. JP07 Br. Ex., BP-16-R-JP07-01, at 5. To the contrary, however, and as explained above, Staff established that it is inappropriate to use a single year of historical data to forecast BPA's secondary revenues for a prospective two-year rate period. Thus, a 20 percent adjustment to a forecast based on such an approach, like the approach itself, would be improper. Furthermore, there is no substantive evidence supporting JP07's apparently arbitrary assumption of a 20 percent adjustment for risk. In addition, contrary to JP07's claim, BPA has proposed an alternative to JP07's approach. This approach, noted above, is a \$10 million ad hoc upward adjustment to the secondary revenue forecast pending further examination. Although JP07 disagrees with the amount of the adjustment, JP07 supports such an adjustment. *Id.* at 2.

Decision

BPA will include additional revenue recovery from secondary energy sales made at extra-regional points of delivery in its forecast of secondary revenue in the BP-16 final rates. To do this, BPA will increase the forecast of secondary revenue by \$10 million, which is a risk-adjusted estimate of potential sales to points of delivery contiguous to California. Prior to the BP-18 rate case, BPA will convene an informal public process to examine BPA's forecasting of secondary energy sales.

2.5 Power Rate Development

Section 2.5 addresses issues related to the Power Rates Study and the power rate schedules, including the general rate schedule provisions. Section 2.5.1 lists changes in rate development methods, rate schedules, and GRSPs proposed by BPA Staff that were not raised in the parties' briefs and thus will be adopted without further discussion.

The Power Rates Study explains the processes and calculations used to develop the rates and billing determinants for BPA's wholesale power products and services. The Power Rates Study serves three primary purposes: (1) to demonstrate that the proposed rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute; (2) to set rates consistent with agency policy; and (3) to demonstrate that the proposed rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period. Power Rates Study, BP-16-FS-BPA-01, at 1.

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, directs the allocation of costs, which is performed in the cost of service analysis, and provides a set of rate directives with further guidance on how individual rates are to be derived. BPA's rates must follow the ratesetting directives of section 7, but, as noted in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue BPA collects from each class of customers, not the rate form. *See, e.g.*, H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess. 69 (1980). Section 7 reserves rate design (how the revenue is collected) to the Administrator.

As described in the Power Rates Study, the cost of service analysis and the other ratemaking steps are programmed into a spreadsheet model, RAM2016, for purposes of calculating power rates. BPA makes the RAM2016 spreadsheet model available to the public on its Web site. The Power Rates Study describes how the tiered PF Public rate is designed following the cost of service and rate directives ratemaking steps. The rate design for the PF Public rate was established in the Tiered Rate Methodology (TRM). The TRM restricts BPA and customers with Contract High Water Mark contracts from proposing changes to the TRM except in a section 7(i) rate proceeding, and only after certain procedures specified in the TRM have been followed. TRM, BP-12-A-03, § 13. No such changes have been proposed by BPA, any customer with a CHWM contract, or any other party in this case. Rates are established to recover the costs of the Residential Exchange Program in accordance with the terms of the 2012 REP Settlement and the Administrator's decisions in the REP-12 ROD. *See* ROD § 1.2.3.

2.5.1 Power Rate Development Changes

In the Initial Proposal, Staff proposed a number of changes to BPA's power rate development, rate schedules, and GRSPs, outlined below. No party raised an issue in its brief with the following changes, and some parties express support for the adoption of these changes. For a more complete explanation and description of each of the changes, see the Power Rates Study, BP-16-FS-BPA-01; the BP-16 Power Rate Schedules, Appendix B to this ROD; Stiffler *et al.*, BP-16-E-BPA-17; Yokota *et al.*, BP-16-E-BPA-21; Weekley *et al.*, BP-16-E-BPA-22; Chalier *et al.*, BP-16-E-BPA-23; and Abadi and Fisher, BP-16-E-BPA-36.

1. **Priority Firm Tier 2 Vintage Rate, VR1-2016.** The new Tier 2 VR1-2016 product and its associated rate allow customers to purchase stepped amounts of power with delivery beginning in FY 2016.
2. **New Resource Rate Schedule: Energy Shaping Services (ESS) Energy Charge (GRSP II.G.1.1).** The energy charge design has more granularity, obviating the need for an annual true-up. That is, the new design effectively provides a true-up monthly by charging a customer for any net energy purchased from BPA during a month at the applicable NR energy rates.
3. **New Resource Rate Schedule: ESS Capacity Charge (GRSP II.G.1.2) and Allocation of Revenues.** The new capacity charge compensates BPA for providing more flexibility to a Load Following customer serving its New Large Single Load (NLSL) with non-Federal resources. Customers will be allowed to change BPA's obligation to provide capacity with at least 30 days' notice prior to the applicable billing month. The capacity that is provided will not be treated as a Designated BPA System Obligation, and the associated revenue will be credited to the Non-Slice cost pool.
4. **New Resource Rate Schedule: Resource Flattening Service (NRFS) Charge (GRSP II.G.2).** The new NRFS charge allows a Load Following customer to apply the generation of a specified resource directly to its NLSL.

5. **Firm Power and Surplus Products and Services (FPS) Rate Schedule.** The FPS rate schedule is clarified and updated to better reflect BPA’s ability to sell certain products and provide services in current wholesale energy and capacity markets.
6. **General Transfer Agreement Service Charges: Transfer Service Operating Reserves Charge (GRSP II.J.2).** The applicability section eliminates a criterion in the BP-14 rate that required that Power Services be assessed Operating Reserve charges from a third-party transmission provider in order for the Transfer Service Operating Reserve Charge to apply. This revision helps maintain parity between directly connected customers and other transfer customers.
7. **General Transfer Agreement Service Charges: WECC [Western Electricity Coordinating Council] and Peak Charges (GRSP II.J.3 and 4).** Charges are added to GTA Service Charges to recover WECC and Peak costs related to BPA transfer customer loads outside its balancing authority area.
8. **Transmission Scheduling Service (TSS): Open Access Technology International, Inc. (OATI) Registration Fee Cost Component (GRSP II.U.4).** The OATI registration fee is now included in customers’ monthly TSS charges to reduce administrative burden.
9. **Supplemental Guidelines (GRSP I.E).** References to a bright-line voltage test for facilities subject to direct assignment have been removed to be consistent with Transmission Services’ “Facility Ownership and Cost Assignment Guidelines.”
10. **Large Project Targeted Adjustment Charge (GRSP II.A.2).** Customers that receive funds through BPA Energy Efficiency’s Large Project Program will pay this new charge that recovers the borrowing costs needed to fund the customers’ projects.
11. **Provisional Contract High Water Marks.** References to Provisional CHWMs have been removed from the BP-16 Power rate schedules and GRSPs because the implementation of Provisional CHWMs is complete.
12. **Recovery Peak Billing Determinant Adjustment (GRSP II.D.2).** The GRSP clarifies when customer loads are considered Recovery Peaks that could qualify for this adjustment.
13. **Low Density Discount (GRSP II.M).** The language is revised to clarify GRSP II.M sections 1, 1(a), and 1(b).
14. **Southeast Idaho Load Service Cost Allocation.** BPA received notice from its current transfer service provider that the exchange agreement and transmission agreement used to serve BPA customers in SE Idaho would terminate on June 30, 2016. An allocation methodology for the power and transmission costs that will be incurred to serve these customers beginning in July 2016 is modeled as described in the Initial Proposal.

15. **Allocation of Diurnal Flattening Service (DFS) Energy Revenue.** DFS energy revenue is allocated to the Non-Slice cost pool rather than the Composite cost pool as in BP-12 and BP-14 rate development. This change aligns the revenue allocation with the treatment of this service operationally through the Slice Computer Application.
16. **Grandfathered Generation Management (GMS) Service Charges (GRSP II.U.5).** Grandfathered GMS allows a customer to run an Existing Resource (that was supported with GMS during FY 2002-2011) against its Tier 1 load. The Grandfathered GMS charges are not new but have been added to the GRSPs to correct an inadvertent omission from earlier GRSPs.
17. **Super Peak Period (GRSP III.B.29).** The definition of the Super Peak Period for June through September has shifted one hour, *from* Hour Ending (HE) 14 through HE 19 *to* HE 13 through HE 18.
18. **Residential Exchange Program Residential Loads and the 7(b)(3) Surcharge Adjustment (GRSP II.S and II.T).** Residential Loads are updated using calendar year (CY) 2013 and CY 2014 investor-owned utility (IOU) residential and farm loads. The 7(b)(3) Surcharge Adjustment is revised to describe how the Surcharge would be adjusted for a change in a participating utility's average system cost during the BPA rate period, regardless of the reason for the change.
19. **Modifications to RAM Cost Table and Slice True-up Table: Other Expense Offset.** In the IPR2, BPA decided that it will expense Energy Efficiency program costs rather than capitalizing those costs. *See* ROD § 1.2.1. BPA intends to use cash flows resulting from an extension of maturing Energy Northwest debt that is currently related to Debt Service Reassignment to mitigate the rate impact of transitioning the core EE investment program to one that is fully expensed and to accelerate an existing plan to repay Federal power appropriations.

A new line item, "Other Expense Offset," is added to (i) the RAM2016 Table 2.3.1, Disaggregated Costs and Credits, and (ii) Table G, Composite Cost Pool True-Up Table, in GRSP II.W. The change to the RAM2016 cost table is necessary to ensure application of cash flows to mitigate the effect of accelerated appropriations repayment and expensing the EE investment program. The change to Table G is necessary to ensure the equitable treatment of Slice and Non-Slice customers. The Other Expense Offset is subject to the Composite Cost Pool True-Up.
20. **Modifications to RAM Cost Table and Slice True-Up Table: PGE WNP-3 Settlement.** In 1998, BPA and PGE entered into a termination agreement of a 1985 power exchange contract that arose out of the decision to terminate construction of the WNP-3 nuclear plant. PGE paid BPA \$74 million in 1998 to settle its contract obligations. That payment is recognized, for accounting purposes, as revenue over the term of the contract until the settlement is fully amortized in 2019. This practice results in \$3.524 million per year of non-cash revenue to BPA.

In the BP-12 and BP-14 rate cases, these non-cash revenues were assigned to the Non-Slice cost pool using the “accrual revenue” line in the cost table. To correct this allocation that placed responsibility for the financial implications of the settlement on Non-Slice customers, even though the benefit (the revenue credit) was shared by both Slice and Non-Slice customers, a new “PGE Settlement” line is added to the RAM Cost Table and Slice True-Up Table G. This new line allocates the non-cash revenue to the Composite cost pool to match costs with benefits. The PGE WNP-3 Settlement is not subject to the Composite Cost Pool True-Up.

21. **PF Rate Schedule: Slice Billing Adjustment.** The new Slice Billing Adjustment corrects for the inaccurate allocation of the PGE WNP-3 Settlement revenues in FY 2012–2015 (see number 20, above) by adjusting Slice customers’ bills by their share of the costs that should have been allocated to them in the previous rate periods. This one-time billing adjustment will be charged to Slice customers on their November 2015 power bills.

2.5.2 Demand Rate

Issue 2.5.2.1

Whether BPA should use an LMS100 or an F-class frame combustion turbine (F-class turbine) as the marginal resource to calculate the demand rate.

Parties’ Positions

WPAG argues that BPA should use an F-class turbine for the marginal resource to calculate the demand rate instead of the LMS100. WPAG Br., BP-16-B-WG-01, at 31. WPAG bases its proposal on its assertion that an F-class turbine would be able to meet the daily and seasonal capacity needs of BPA’s preference customers for load service and at a lower annual fixed cost than the LMS100. *Id.*

JP11 disagrees with WPAG and contends that WPAG’s justification for the use of an F-class turbine is related solely to the cost of capacity with no reference to actual capability. JP11 Br., BP-16-B-JP11-01, at 6. JP11 further states that the system managed by BPA is significantly different from most systems across the United States and that BPA cannot be bound by the capacity resource choices of other utilities. *Id.* at 6-7.

ICNU disagrees with WPAG and argues that the Administrator should select the resource used for calculating the demand rate based on the lowest-cost resource that is actually being built and used by utilities to meet their long-term loads. ICNU Br., BP-16-B-IN-01, at 7. ICNU states that an F-class turbine has limited operational flexibility when compared to aeroderivative technologies, including the LMS100. *Id.* ICNU points out that no utility in the Northwest has built an F-class turbine since 2008; instead, utilities have built three aeroderivative facilities in 2010 and 2011, and most recently PGE built a reciprocating engine facility. *Id.*

BPA Staff's Position

Staff proposes using an LMS100 combustion turbine as the basis for the demand rates. Stiffler *et al.*, BP-16-E-BPA-17, at 2. Staff disagrees with WPAG's proposal to use an F-class turbine to set the demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 2. Staff uses the LMS100 to set the demand rate due to its operational flexibility. *Id.* at 3. Operational flexibility is an important quality for the resource used to price the demand rate due to the demand rate's link with Resource Support Services (RSS). *Id.* The F-class turbine, as proposed by WPAG, does not have the operational flexibility required by BPA's RSS. *Id.* The demand rate should be based on a resource that is actually being built and used by utilities to meet their long-term loads. *Id.* at 4. The LMS100 has become the industry standard for a flexible natural gas-fired peaking resource in the Western Interconnect, as evidenced by the 25 LMS100 plants that either are in operation or have recently been completed in California alone. *Id.*

Evaluation of Positions

The TRM requires that BPA identify the marginal capacity resource used to set the Tier 1 demand rate in each section 7(i) proceeding. The TRM states that the demand rate shall be based on the "annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process." TRM, BP-12-A-03, at 76. The TRM also establishes that "the capacity component of each RSS service will be priced at the Demand Rate" *Id.* at 89.

Consistent with the past two rate cases, Staff proposes to use General Electric's LMS100 as the marginal capacity resource used to set the Tier 1 demand rate. Power Rates Study, BP-16-E-BPA-01, at 71; Stiffler *et al.*, BP-16-E-BPA-17, at 2. The LMS100 is a combustion turbine that is known for its operational flexibility. Abadi and Fisher, BP-16-E-BPA-36, at 2. The cost of the LMS100 sits in the middle of the four commonly recognized combustion capacity technologies used to meet a utility's capacity needs: heavy industrial frames (such as the F-class as proposed by WPAG), intercooled turbines (such as the LMS100), aeroderivatives, and reciprocating engines (such as the 12 Wärtsilä engines recently built by PGE). *Id.* at 7. An F-class turbine is expected to be the cheapest, though it does not have the operational flexibility found in the other three capacity technologies. *Id.* at 8; ICNU Br., BP-16-B-IN-01, at 7.

At the time of the BP-12 rate case, the LMS100 was a relatively new design and had not been built very widely. However, despite its newness, the LMS100's operational advantages, namely its flexibility-to-cost ratio, caused it to be identified as a strong candidate to meet future capacity needs. Several other inputs to the demand rate calculation were at issue in the BP-12 Record of Decision, but the use of the LMS100 as the resource used to set the demand rate was not contested. BP-12 Administrator's Final Record of Decision, BP-12-A-02, at 110-119.

Since the BP-12 rate case, the LMS100 has established itself as the industry standard for flexible capacity. Abadi and Fisher, BP-16-E-BPA-36, at 2. There are now nearly 30 LMS100 units either under construction or recently built across the Western Electricity Coordinating Council, almost all of them in California. *Id.* No LMS100s have been built in the Pacific Northwest, but several other flexible capacity resources have been. ICNU Br., BP-16-B-IN-01, at 7. The last F-class turbine in the Pacific Northwest was built in 2008. Abadi and Fisher, BP-16-E-BPA-36,

at 4; ICNU Br., BP-16-B-IN-01, at 7. Three aeroderivatives were built in the Pacific Northwest in 2010 and 2011. ICNU Br., BP-16-B-IN-01, at 7. The most recent capacity additions in the Pacific Northwest are the reciprocating engines built by PGE at its Port Westward location. Abadi and Fisher, BP-16-E-BPA-36, at 8; ICNU Br., BP-16-B-IN-01, at 7.

Staff's proposal in this case is consistent with the decision made in the BP-12 ROD, which was to use the LMS100 as the resource for the basis of the demand rate. The resources being built in the Pacific Northwest and Western Interconnect demonstrate a significant preference for flexible capacity resources, such as the LMS100. Abadi and Fisher, BP-16-E-BPA-36, at 4. In addition, incidence of construction of the LMS100 has grown considerably, making it the current industry standard for a flexible natural gas-fired peaking resource. *Id.* at 2.

As indicated above, for BPA the concept of resource operational flexibility is central to identifying the marginal capacity resource. WPAG asserts that an F-class turbine would be able to meet the daily and seasonal capacity needs of BPA's preference customers for load service and at a lower annual fixed cost than the LMS100. WPAG Br., BP-16-B-WG-01, at 31. WPAG asserts that good utility practice dictates that a utility select the marginal resource that will meet its needs at the lowest possible cost, which WPAG states is consistent with BPA's statutory obligation to encourage the widest possible diversified use of electric energy at the lowest possible rates. *Id.* Staff, however, disagrees that the F-class turbine would meet BPA's capacity needs and notes that the LMS100's operational flexibility is needed to provide RSS, which is also tied, pursuant to the TRM, to the same capacity price signal as load. Abadi and Fisher, BP-16-E-BPA-36, at 3.

JP11 also disagrees that the F-class turbine would meet BPA's capacity needs and states that WPAG provides no backup or support for its claim. JP11 Br., BP-16-B-JP11-01, at 6. JP11 also states that WPAG's argument is related solely to the cost of capacity with no reference to actual capability. *Id.* WPAG disputes, through a footnote in its brief, that RSS requires flexible capacity, but neither provides support for its claim nor responds to Staff's description of RSS that explains that RSS requires flexible capacity. WPAG Br., BP-16-B-WG-01, at 32 n.14. In addition to the description of the services in the Power Rates Study, BP-16-E-BPA-01, § 3.1.15, Staff notes that the products detailed in Diurnal Flattening Service (DFS) and Forced Outage Reserve Service (FORS), which are services provided under the RSS umbrella, require a fast-ramping, flexible capacity resource. Abadi and Fisher, BP-16-E-BPA-36, at 3. In particular, the provision of DFS requires following an intermittent resource hour to hour in order to convert it to a flat diurnal block. *Id.* Only a flexible resource can accomplish this. *Id.* Temporarily setting aside potential differences in the needs of loads and resources, the record is clear that an F-class turbine does not have the operational flexibility needed to provide RSS and therefore will not meet BPA's needs at the lowest possible cost. *Id.*

Further, WPAG is incorrect in its statement that this issue relates to BPA's statutory obligation to encourage the widest possible diversified use of electric energy at the lowest possible rates. The issue at hand is a rate design issue and is applied after BPA has allocated its total power revenue requirement. Power Rates Study, BP-16-FS-BPA-01, § 3. Rate design does not change the amount of the revenue requirement that is allocated; rather, rate design determines from which

customers the revenue requirement is collected. *Id.* at 53. In other words, this issue, specifically the level of the demand rate, does not change the amount of revenue collected by BPA and thus does not impact BPA's effective rate level. BPA's statutory obligation of lowest possible rates does not extend to each and every element of BPA's rates; BPA's governing statutes also grant the Administrator discretion in establishing different rate forms within the context of lowest possible rates. 16 U.S.C. § 839e(e).

WPAG also claims that the TRM does not specifically allocate the cost of flexibility to demand rates; therefore, the cost of flexibility should be allocated pursuant to the TRM's Cost Allocation Principle Number 2, which states: "Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefits from such costs." WPAG Br., BP-16-B-WG-01, at 32-33, *citing* TRM-12S-A-03, at 3. WPAG states that because RSS customers are those that benefit from the added flexibility of the LMS100, only RSS customers should be allocated the cost of flexibility. WPAG Br., BP-16-B-WG-01, at 33. WPAG adds that this allocation should be not through the demand rate but through a separate and distinct allocation because the demand rate is paid by non-RSS customers that are not benefited by the additional flexibility of the LMS100. *Id.* Despite the appeal of this argument, the TRM expressly addresses the allocation of capacity (flexible or otherwise) used to provide BPA's RSS. The TRM states that "the capacity component of each RSS service will be priced at the Demand Rate." TRM, BP-12-A-03, at 89. Therefore, the TRM language renders irrelevant the potential technical differences in how loads and resources consume capacity. The price signal used to allocate capacity costs to loads must also be used to price RSS. A change of the TRM would be required to distinguish between the demand rate for load service and the demand rate for RSS.

Only one resource can be selected for the purpose of setting the demand rate; therefore, the positive and negative attributes of each resource must be considered. It is undisputed that the LMS100 is operationally more flexible than the F-class turbine and the F-class turbine is less expensive than the LMS100. Abadi and Fisher, BP-16-E-BPA-36, at 3, 8. WPAG contends that not only is the F-class turbine less expensive; it should be used for setting the demand rate because the capacity sold for RSS is a small portion of the overall demand rate revenue BPA receives. WPAG Br., BP-16-B-WG-01, at 32. Staff, however, states that the price signal needs to remain true to the underlying product being offered, regardless of the relative size of the revenue collected. Abadi and Fisher, BP-16-E-BPA-36, at 7. Staff further states that the flexibility required by RSS cannot be ignored, and the LMS100 is a significantly better fit than the F-class turbine. *Id.* Staff's positions have merit.

ICNU argues that the use of the F-class turbine would distort the price signal and cause utilities to lean on BPA for capacity. ICNU Br., BP-16-B-IN-01, at 8. The type of capacity needed to provide RSS is required to be more flexible than an F-class turbine and is therefore more expensive. Pricing RSS based on an operationally inadequate but less-expensive marginal resource would economically bias customers toward purchasing all their RSS requirements from BPA. This outcome does not align with one of the intentions of tiered rates and the Regional Dialogue Policy, which is to promote infrastructure development and remove a financial

disincentive for BPA customers to develop regional infrastructure. Bonneville Power Administration Long-Term Regional Dialogue Final Policy, at 8 (July 2007).

With regard to revenue collection, WPAG correctly points out that the bulk of BPA's demand revenue collection is from the Tier 1 demand charge and not from providing RSS. WPAG Br., BP-16-B-WG-01, at 32. WPAG uses this revenue collection ratio to support the use of the F-class turbine, which WPAG claims has sufficient operational capability to meet load. *Id.* at 31. WPAG's argument, however, misses an important component—the billing determinant applied to the demand rate. Pursuant to the TRM, the demand charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA. TRM, BP-12-A-03, at 71. The operative word in this instance is "limited." While the applicable rate is the same, the effective cost of capacity between loads and RSS is significantly different, as the demand rate for RSS is applied to all capacity BPA provides and not a limited portion as is true for load. In addition, WPAG's argument ignores the history behind the amount of revenue collected by load. The amount paid is largely the result of the negotiations that occurred when BPA and its customers collaboratively drafted the TRM and balanced the rate impacts caused by the TRM and the amount of load to be exposed to the demand rate. In other words, WPAG's argument is incomplete and is based on only one facet of a much more complex rate design.

Finally, the source of the capacity currently consumed by both load service and RSS is primarily hydro resources, which are generally considered very flexible resources. TRM, BP-12-A-03, at 139. Until BPA purchases additional capacity, the demand rate serves as a price signal that not only encourages utility demand-saving investment but also compensates other customers for increased use of the Tier 1 System capacity by those actually using it. Given this benefit, it is reasonable to compensate other customers for increased use of the Tier 1 System at the cost of flexible capacity, given that the Tier 1 System is a source of flexible capacity.

Decision

BPA will continue to use the LMS100 as the marginal resource to calculate the demand rate for the BP-16 rate period.

Issue 2.5.2.2

Whether BPA should include a planning reserve margin in calculating the demand rate.

Parties' Positions

ICNU argues that a reserve margin is traditionally included when utilities calculate the cost of long-run marginal capacity for ratemaking purposes to reflect the cost of maintaining surplus capacity—beyond that needed to meet peak load—to ensure system reliability during peak demand events. ICNU Br., BP-16-B-IN-01, at 4. ICNU argues that BPA should rely on the planning reserve margin target established for hydro systems by the North American Electric Reliability Corporation and, as a result, should increase the demand charge to \$10.27/kW/mo. to account for a reserve margin of 10 percent. *Id.* at 5.

JP02 disagrees with ICNU, stating that BPA should not apply a technique used in utilities' long-term planning analyses (e.g., Integrated Resource Plans) to a rate case construct intended to send a price signal. JP02 Br., BP-16-B-JP02-01, at 2-3. JP02 argues that including the cost of a reserve margin in the demand rate would result in double-recovery of certain costs in BPA's rate structure. *Id.* at 3-4.

WPAG also disagrees with ICNU, stating that including the cost of a reserve margin in the demand rate would double-count load risk that is already accounted for through AURORA^{xmp}® modeling. WPAG Br., BP-16-B-WG-01, at 33.

BPA Staff's Position

Staff notes that the TRM states that the demand rate is to be based on the annual fixed costs (capital and O&M) of the marginal capacity resource, which do not include reserve margins. Abadi and Fisher, BP-16-E-BPA-36, at 8.

Evaluation of Positions

ICNU argues that a reserve margin is traditionally included when utilities calculate long-run marginal capacity for ratemaking purposes to reflect the cost of maintaining surplus capacity—beyond that needed to meet peak load—to ensure system reliability during peak demand events. ICNU Br., BP-16-B-IN-01, at 4. ICNU states that a reserve margin is traditionally stated as a percentage of peak load, citing the practice of various Pacific Northwest utilities. *Id.* ICNU argues that a reserve margin is embedded in the long-run cost of demand and should also be included in the demand rate charged to customers to send a correct price signal and reflect the cost for marginal capacity incurred on the system. *Id.*

In response to ICNU's arguments, first, there are established rules that govern the inclusion of costs in BPA's demand rate. The TRM states that "BPA will base the Demand Rate on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process." Abadi and Fisher, BP-16-E-BPA-36, at 8-9, *citing* TRM, BP-12-A-03, at 76. Capital and O&M costs for a generator do not include a reserve margin. Furthermore, there is no provision in the TRM that calls for BPA to include a planning reserve margin in the demand rate calculation. Abadi and Fisher, BP-16-E-BPA-36, at 8. BPA's demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as calculated by the Northwest Power and Conservation Council's Microfin model 15.0.1. Power Rates Study, BP-16-E-BPA-01, at 71. This calculation is consistent with the TRM. Abadi and Fisher, BP-16-E-BPA-36, at 9. It includes fixed costs of the resource, as mandated by the TRM, but does not include reserve margins. *Id.*

Staff cites a presentation by the Northwest Power and Conservation Council that lists the components of the cost of the LMS100 intercooled combustion turbine. *Id.* The Council's presentation does not list a reserve margin as a component of the cost of the LMS100 turbine. *Id.* Thus, Staff contends, reserve margins are not a proper component of BPA's long-run fixed cost of capacity. *Id.* This is a sound argument.

Second, contrary to ICNU’s claim, reserve margins do not represent the *cost* of maintaining surplus capacity. *Id.* The North American Electric Reliability Corporation defines the term “Planning Reserve Margin”:

Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy.

<http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx>. BPA engages in long-term resource planning, as documented in the Needs Assessment and Resource Program, to ensure that the Federal system will operate reliably during peak times. Abadi and Fisher, BP-16-E-BPA-36, at 9-10. This planning concept is different from the demand rate, which is a price signal to customers designed to reflect the actual unit cost of marginal capacity. *Id.* at 10; JP02 Br., BP-16-B-JP02-01, at 3.

Third, ICNU refers to the reserve margins of Pacific Northwest utilities. ICNU Br., BP-16-B-IN-01, at 4. This issue is addressed in Staff’s rebuttal testimony. Although PGE, for example, may use a 12 percent planning reserve margin in calculating its marginal cost of capacity, ICNU does not cite any source indicating why PGE does so. Abadi and Fisher, BP-16-E-BPA-36, at 10. PGE’s 2013 Integrated Resource Plan (IRP), states:

The level of reserves we include in planning for capacity is important for maintaining supply reliability. We plan for approximately 12% of reserves, comprising 6% contingencies and an approximately 6% operating reserve margin. The operating reserve margin is required by Western Electricity Coordinating Council (WECC) reliability standards and is intended to maintain supply stability and power quality during unexpected real-time disruptions within the operating hour (i.e., must be compensated for within one hour). Examples of disruptions include plants unexpectedly going off-line and unanticipated load increases. The contingency reserve covers two types of events: 1) extreme weather events and resulting load excursions (i.e., loads going above those associated with average, or “1-in-2”, weather); and 2) unplanned generator or transmission outages (either full or partial) extending beyond the time to be covered by operating reserves.

Portland General Electric, *2013 Integrated Resource Plan* § 3.3 (March 2014). PGE’s 2013 IRP shows that PGE’s reasons for using a 12 percent reserve margin in its calculation of marginal capacity are different from the reasons behind the development of BPA’s demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 10. The foregoing quotation states that PGE’s reserve margin includes 6 percent for contingencies and 6 percent for operating reserves. *Id.* BPA bills and accounts for “Operating Reserves” separately as ancillary and control area services provided by BPA’s Transmission Services. *Id.* at 10-11, *citing* Transmission Rates Study and Documentation, BP-16-E-BPA-07, at 115. In addition, with regard to PGE’s “contingency reserves,” when a weather event occurs and loads spike, the weather event impacts the billing determinant applicable to the BPA demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 11.

Including the cost of the weather event in both the billing determinant and the rate would result in double-counting. *Id.*

The foregoing quotation also mentions unplanned generator or transmission outages extending beyond the time to be covered by operating reserves. *Id.* at 11. This concept follows the same principle as BPA's Forced Outage Reserve Service, which accounts for events that last longer than the amount of time covered by Operating Reserves. *Id.* The TRM defines FORS as "the service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource FORS may be arranged for when Operating Reserves expire or when the resource operator recognizes imminent failure and must initiate a controlled shutdown." *Id.*, citing TRM, BP-12-A-03, at 90. The cost basis for FORS is the PF demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 11. BPA would be double-counting if the demand rate also included the cost of providing contingency and operating reserves. *Id.* JP02 also notes that including the cost of a reserve margin in the demand rate would result in double-recovery of certain costs in BPA's rate structure. JP02 Br., BP-16-B-JP02-01, at 2-3.

In response to the claim that including a reserve margin would constitute double-counting, ICNU argues that Staff fails to recognize that marginal capacity is part of a proper price signal, and that the reserve margin that would be associated with marginal capacity, should it be built, would have an incremental cost. ICNU Br., BP-16-B-IN-01, at 5. ICNU asserts that, likewise, while reserves needed for *existing* resources are built into BPA's Ancillary and Control Area Service rate and the PF demand rate, these rates do not reflect reserve margins for marginal resources that would need to be constructed if demand is not controlled. *Id.* Thus, ICNU claims, there is no double-counting when a reserve margin is incorporated into the demand charge; rather, a more accurate reflection of the cost of incremental resources is included in the price signal. *Id.*

In response to ICNU, the design of the demand rate already reflects the cost of *marginal* capacity, or capacity that has not been built. TRM, BP-12-A-03, at 76-77. As such, it includes (as the TRM mandates) the fixed costs (capital and O&M) of that marginal capacity resource. Abadi and Fisher, BP-16-E-BPA-36, at 8. As a price signal, the demand rate must reflect the costs associated with that resource and nothing else. As mentioned above, including a reserve margin in the demand rate would add costs that are already being collected in other parts of BPA's rates. *Id.* at 11, citing TRM, BP-12-A-03, at 90.

ICNU's argument is also incomplete as it ignores the multiple price signals being sent to customers through BPA's other rates and assumes that the demand rate is the only source of BPA's price signal for increased use of capacity. An increase in a customer's demand will cause the customer to incur additional demand costs as well as additional ancillary and control area services costs. Abadi and Fisher, BP-16-E-BPA-36, at 10. This fact results in a customer being exposed to a price signal for both components, the first through BPA's demand rate and the second through BPA's ancillary and control area service rates.

ICNU also inappropriately distinguishes between cost recovery for existing resource costs and the price signal for resources that have not yet been constructed. The price signals sent by BPA are consistent for a reduction or an increase in a customer's existing demand. There is no hard

separation between existing and future demands because the definition of “existing” is relative to the time in which the measurement is made. In other words, today’s future demand will be tomorrow’s existing demand. Given that the definition of “existing” is time relative, it is impossible to reconcile ICNU’s argument because ICNU concedes that “reserves needed for existing resources are built into BPA’s Ancillary and Control Area Service rates and the PF demand rate.” ICNU Br., BP-16-B-IN-01, at 5. Moreover, it would be inappropriate to charge existing loads on the prospect of resource costs being incurred for future loads when those future loads are not yet certain. A customer should be charged for added capacity use only if and when those future loads materialize, which is the case with BPA’s multifaceted rate design.

ICNU argues that WPAG’s parallel assertions that a reserve margin would change the nature of the demand rate or cause double-recovery are untrue. ICNU Br., BP-16-B-IN-01, at 5-6. ICNU notes WPAG’s argument that BPA already accounts for load risk, a component of reserve margins, in its calculation of power rates based on the use of stochastic modeling. *Id.* ICNU claims that this argument misses the point because the issue is not whether power rates, overall, account for reserve margins; rather, the issue is whether the reserve margin costs are properly allocated to the demand rate component of overall power rates. *Id.* ICNU states that the point WPAG misses is that these reserve margin costs are not being allocated to the demand rate component of overall power rates. *Id.* at 6. ICNU states that it follows that the inclusion of a reserve margin in demand rate calculations would result in an appropriate and effective price signal and should be adopted by the Administrator. *Id.*

While BPA generally agrees with ICNU’s arguments against WPAG’s position, ICNU does not gain any ground because its arguments are essentially the same as made against Staff’s position, which are addressed above. The demand rate is not the only price signal customers observe through BPA’s rates for the increased use of capacity. Further, the demand charge was not designed as the only method to collect capacity-related costs from customers, as demonstrated by BPA’s multiple capacity-based rates. Nor was the demand charge designed to recover all capacity costs associated with load service, as evidenced by its limited billing determinant and complete lack of applicability to Slice/Block and Block-only customers. TRM, BP-12-A-03, at 71.

Fourth, ICNU notes that regional utilities use some degree of a reserve margin construct when determining the amount of capacity that must be built or acquired to maintain reliable operations. ICNU Br., BP-16-B-IN-01, at 4; *see also* Mullins, BP-16-E-IN-01, at 9. Staff agrees that regional utilities plan for and acquire resources in excess of their anticipated peak load to maintain reliable operations; this amount of resources expressed as a percentage of the expected peak load can be thought of as a reserve margin. Abadi and Fisher, BP-16-E-BPA-36, at 12. However, the issue at hand is whether that planning reserve margin should be reflected in the price signal for the marginal cost of capacity. Staff maintains that whether the planning reserve margin is assumed to be 10 percent, 12 percent, or some other calculated or arbitrary number, the cost of marginal capacity will continue to be fixed costs associated with building the GE LMS100 intercooled combustion turbine, and not those fixed costs increased by 10 percent or 12 percent. *Id.* This is because the costs are expressed as a per-unit amount and not a lump

dollar sum. *Id.* The per-unit amount will not increase with additional units. *Id.* This argument is well-founded.

ICNU argues that BPA should rely on the planning reserve margin target of 10 percent established for hydro systems by the North American Electric Reliability Corporation. ICNU Br., BP-16-B-IN-01, at 5. NERC's definition of a planning reserve margin is quoted above. Abadi and Fisher, BP-16-E-BPA-36, at 13. The NERC standard deals strictly with the amount of generation needed to meet load, not cost. *Id.* NERC's recommendations do not suggest that BPA should raise its demand rate by 10 percent. *Id.*

Decision

BPA will not include a planning reserve margin in calculating the demand rate.

Issue 2.5.2.3

Whether BPA should include a pipeline capacity release credit in the computation of the demand rate.

Parties' Positions

ICNU argues that BPA should remove the assumption that any fixed fuel costs associated with the demand rate could be mitigated by selling off pipeline capacity. ICNU Br., BP-16-B-IN-01, at 6-8. ICNU states that the Northwest Power and Conservation Council (Council) already removed this assumption from its analysis in the Sixth Power Plan. *Id.* at 6. ICNU also asserts that firm pipeline capacity release is a variable cost, not a fixed cost, removing any relevance to the demand rate, which should be based solely on fixed costs. *Id.* at 6-7.

JP02 argues that when the Council removed this credit from the Sixth Power Plan, it recognized that even though capacity release credits may be falsely precise for long-term planning purposes, they are a component of currently operating resources. JP02 Br., BP-16-B-JP02-01, at 4-5. Therefore, JP02 claims, it is reasonable to include the capacity release credit for purposes of setting BPA's demand rate. *Id.*

WPAG argues that ICNU's position that firm pipeline capacity is a variable cost would treat the gas transportation reservation costs as demand-related but revenue credits from the same as energy-related. WPAG Br., BP-16-B-WG-01, at 33-34. WPAG states that under standard ratemaking practice, revenue and credits such as this should retain the same classification. *Id.* at 34. WPAG asserts that ICNU's proposal treats BPA's demand rate calculation as a long-term fixed cost calculation, whereas it is more accurately identified as a short-term fixed cost calculation. *Id.* Under short-term fixed cost calculations, WPAG states, the inclusion of revenue credits from the sale of capacity rights is the correct approach. *Id.* WPAG argues that the revenue received from the resale of pipeline capacity rights is fixed rather than variable revenue. WPAG Br. Ex., BP-16-R-WG-01, at 3-7. WPAG asserts that even if pipeline capacity release

credits are not fixed revenue, they should be included in the demand rate calculation under cost causation principles. *Id.*, at 7-9.

BPA Staff's Position

Staff's Initial Proposal included a 10 percent capacity release credit in the calculation of the Tier 1 demand rates. Power Rates Study Documentation, BP-16-E-BPA-01A, Table 3.4. Staff does not address this issue in its testimony.

Evaluation of Positions

ICNU argues that, as currently proposed, the demand charge is artificially reduced because it includes an assumption that 10 percent of the fixed fuel transportation costs associated with the LMS100 capacity resource would "be recovered through resale of the pipeline rights or capacity release credits." ICNU Br., BP-16-B-IN-01, at 6, *citing* Mullins, BP-16-E-IN-01, at 10-11. ICNU claims that this assumption is arbitrary and should be removed from the demand charge. *Id.* ICNU notes that when it requested information regarding the source of the capacity release assumption, BPA was able to point to no study or work papers to demonstrate its reasonableness; rather, BPA pointed to testimony from BP-12, in which Staff acknowledged that the Council no longer retains a capacity release assumption. *Id.* ICNU claims that BPA declined to adjust its proposal to follow the Council's practice on the basis that the small size of the change it would make in the demand rate did not warrant the adjustment. *Id.* ICNU argues that without any analytical basis for retaining this assumption, there is no sound business reason for including it in the demand rate. *Id.*

JP02 disagrees with ICNU and points out that BPA already considered this argument in the BP-12 rate case. JP02 Br., BP-16-B-JP02-01, at 4. In that rate case, it was determined that the Council removed the pipeline capacity release credit because the Council thought it provided false precision for long-term planning purposes and not because it was an unreasonable assumption. *Id.* at 4-5. JP02 also states that the Council still recognizes that capacity-release capability is available in firm gas transportation contracts. *Id.* at 4. JP02 further notes that the demand rate is not a long-term planning concept but rather a rate to send a price signal to a limited portion of a customer's overall demand on BPA. *Id.* at 5. In contrast to ICNU, JP02 argues that the removal of the capacity release credit would artificially increase the demand rate and would cause the demand rate to be less accurate than it otherwise would be. *Id.*

It is undisputed that capacity-release capability is included in firm gas transportations contracts. JP02 Br., BP-16-B-JP02-01, at 4. Further, no party disputes that at some point prior to the release of the Council's Sixth Power Plan, the Council included a 10 percent pipeline capacity release credit in its estimate of the fixed cost of a natural gas combustion turbine. However, as ICNU correctly points out, there is nothing on the record that explains the methodology that the Council used to reach its 10 percent assumption. Rather, what is on the record is a statement by Council staff that the assumption was removed for purposes of long-term planning and not because it was determined to be unreasonable. JP02 Br., BP-16-B-JP02-01, at 4. This assumption was uncontested in two rate cases, BP-12 and BP-14.

Although, as ICNU correctly points out, the 10 percent value was based on analysis conducted by the Council and this analysis is not in the BP-16 record, the Council's conclusion remains in the record. Given the Council's practice of public and collaborative development of the inputs to its long-run resource planning model (Microfin) and the statement of Council staff prior to the BP-12 rate case, which is on the record, it is unlikely the Council arbitrarily used a 10 percent assumption. If this were the only argument presented against the capacity release credit, it might be prudent to postpone the decision on this issue until BP-18 to avoid unnecessary demand rate volatility. This, however, is not the only argument raised by ICNU in opposition to the pipeline capacity release credit.

ICNU also argues that the release of pipeline capacity is a variable credit that depends, like fuel costs, upon the level of operation of the turbine and also upon market conditions for short-term pipeline capacity. ICNU Br., BP-16-B-IN-01, at 6-7. ICNU claims that, as a result, the credit should not be included in the calculation of fixed costs, and BPA should increase the demand rate by approximately \$0.33/kW/mo. to account for removal of variable capacity release credits. *Id.* WPAG disagrees with ICNU and argues that ICNU's proposal treats BPA's demand rate calculation as a long-term fixed cost calculation, whereas it is more accurately identified as a short-term fixed cost calculation. WPAG Br., BP-16-B-WG-01, at 34. WPAG claims that under short-term fixed cost calculations, the inclusion of revenue credits from the sale of capacity rights is the correct approach. *Id.* WPAG also argues that the elimination of the assumed 10 percent capacity release credit in the demand rate calculation would treat the gas transportation reservation costs as demand-related, but revenue credits from such costs as energy-related. *Id.* at 33-34. WPAG states that under standard ratemaking practice revenue and credits such as this should retain the same classification. *Id.* at 34.

WPAG argues that BPA wrongly concludes that the costs of acquiring pipeline capacity and the revenue from reselling that capacity should not be given uniform treatment for purposes of setting the demand rate. WPAG Br. Ex., BP-16-R-WG-01, at 8. WPAG states that the general rule that related costs and revenues should receive uniform treatment is grounded firmly in cost-causation principles, which are the very foundation of the TRM. *Id.* WPAG argues that the TRM's cost allocation principle number two provides that "Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefit from such costs[.]" *citing* TRM, BP-12-A-03, at 3. *Id.* WPAG claims that the obvious and natural corollary of principle number two's statement of cost causation is that benefits should be allocated to the cost pool(s) that pays the costs from which the benefits are derived, and this is where BPA's analysis breaks down. *Id.* WPAG states that BPA recognizes that a pipeline capacity release credit is a revenue credit a utility would receive after it first incurred a fixed cost for the full pipeline capacity rights and that BPA also proposes to recover the fixed cost associated with such pipeline capacity rights under the demand rate. WPAG Br. Ex., BP-16-R-WG-01, at 9.

WPAG asserts that given these two factors, under the general rule of uniform treatment of costs and benefits and the underlying cost causation principle that benefits should follow costs, the correct allocation of capacity release credits is to the customers that pay the demand rate. That is, the customers that pay the fixed costs associated with pipeline capacity rights should receive

the benefit (*i.e.*, the revenue credits) from the resale of such capacity. *Id.* WPAG claims that for BPA not to allocate or credit the pipeline capacity release credit revenue to any customers, let alone those customers that pay the demand rate, would be inconsistent with cost causation principles. *Id.* In addition, WPAG asserts that it effectively means BPA would be selling a portion of its contracted-for pipeline capacity rights twice, *i.e.*, once to preference customers under the demand rate and once again upon the resale of said rights to a third party. *Id.* WPAG concludes that this practice would cause BPA to over-collect its revenue requirement and create a price signal for the demand rate that does not reflect the true marginal cost of capacity, but instead something higher. *Id.* WPAG claims that BPA needs a mechanism to credit the pipeline capacity credits back to those customers that pay the demand rate to avoid such an over-collection of its revenue requirement, and the inclusion of release credits in the demand rate calculation achieves this purpose. *Id.* at 10.

First, WPAG's over-collection concerns are unfounded. To the extent BPA actually purchased the output of a resource, all costs and revenues would be taken into consideration when setting rates. *See* 16 U.S.C. § 839e(a)(1). Assuming pipeline capacity release or any other such revenue streams materialized in a measurable and significant way, those revenues would be taken into consideration to avoid over-collection of the revenue requirement. Over-collection concerns aside, WPAG raises an equity issue regarding BPA's adherence to cost causation principles and the adage that benefits should follow costs. The answer to the application of cost causation principles is quite simple—if BPA was actually paying pipeline reservation costs and recognizing pipeline release credits, the costs and credits should go to the same customers; however, the fixed costs would be incorporated into the demand rate and the release credits, being a variable cost, would be incorporated into an energy rate.

The counterpoint to WPAG's underlying argument, however, is that the demand rate is a price signal that is aimed to resemble the actual cost of new capacity but in application will never be equal to the actual cost incurred. This is because, pursuant to the TRM, the demand rate is set based on the *expected* annual fixed costs, but the *actual* cost incurred over the life of the capacity purchase will be allocated to one of the cost pools pursuant to TRM section 3.4. TRM, BP-12-A-03, § 3.4. Differences between forecasts and actuals will impact cash reserve levels and, potentially, the Slice True-up, depending on the treatment adopted in the ratesetting process. The TRM does not include a demand charge true-up or other similar provisions that would ensure a direct allocation of the costs of new capacity to the customers causing the cost to be incurred. Directly allocating capacity costs was not the demand charge's intent, as this purpose would require a significantly different rate design. Thus, the cost risk associated with such capacity purchases will be borne by customers that are not exposed to the demand rate. The questions at that time will be "by which customers" and "to what extent." There is not enough information available to determine the equitable allocation of costs and benefits of a hypothetical capacity purchase. If the output of a capacity resource is purchased, BPA and its customers will have to evaluate the facts at that time and determine how best to apply the principle of cost causation. Until then, the TRM is clear that the demand rate will be set on the annual fixed costs of the marginal capacity resource.

WPAG argues that the fact that the proxy resource used for purposes of calculating the demand rate is a hypothetical resource for which BPA does not actually pay any costs or receive any revenue should not change the conclusion that a failure to allocate the pipeline capacity credits back to customers for purposes of setting the demand rate would result in an over-collection of BPA's revenue requirement. WPAG Br. Ex., BP-16-R-WG-01, at 9. WPAG notes that BPA's studies assume that the value of resales of pipeline capacity would equal 10 percent of the fixed fuel transportation costs, and BPA must treat this assumed revenue as if it is as real for purposes of calculating the demand rate as any of the assumed costs that go into the demand rate calculation. *Id.* WPAG claims that BPA is required to allocate that revenue to the customers that pay the demand rate. *Id.*

As noted above, this is not an over-collection issue but rather a potential equity issue that will be in need of further cost causation considerations if BPA purchases the output of an actual capacity resource to provide load service. Pipeline capacity release revenue is but one potential variable revenue benefit that must be weighed against other potential cost and benefit risks that will undoubtedly emerge from the purchase and operation of a capacity resource, such as the LMS100 presently used to set the demand rate. Counter to WPAG's claim, the hypothetical nature of the current resource is a critical consideration given it obscures the facts needed to prove or disprove the potential equity issue raised by WPAG. What is known now is that: (1) the tiered rate design does not directly allocate new capacity resource costs to those that pay the demand charge; (2) the actual cost of a capacity resource will undoubtedly be different from the revenue recovered by the demand rate; and (3) the TRM demand rate language is silent on potential variable benefits associated with the marginal capacity resource. Furthermore, under traditional cost-of-service ratemaking, fixed costs are recovered through demand rates and variable costs through energy rates. For WPAG's view to prevail, it must be demonstrated that the pipeline release credits are a fixed cost and not a variable cost. WPAG's arguments to this end are unavailing—pipeline capacity reserved for the generation of electric capacity cannot be released until it has been determined that there is no need for the electric generation; at that moment in time, the realized credits would no longer be demand-related, but energy-related.

In any case, WPAG's arguments regarding long-term costs, short-term costs, energy costs, and demand costs are misplaced. In this instance, this is not a long-term versus short-term cost issue. Nor is this an energy versus capacity cost issue. Rather, it is a fixed versus variable cost issue. The TRM is clear that the pipeline capacity release credit should be included for purpose of setting the demand rate if it is characterized as a reduction in the fixed cost. TRM, BP-12-A-03, at 76-77. Conversely, the TRM is equally clear that the pipeline capacity release credit should *not* be included for purposes of setting the demand rate if it is characterized as variable revenue. *Id.* As stated earlier, it is undisputed that the Council at one point characterized the capacity release credit as a reduction in fixed costs. However, also undisputed is that the Council no longer uses this assumption as an element of fixed cost in its long-term planning calculations.

Whether pipeline capacity release is variable revenue and not a reduction in fixed cost is the controlling issue. This is the more compelling argument against including a pipeline capacity release credit in the calculation of the demand rate. The description of the pipeline capacity release credit supports ICNU's argument. The credit is described as an offsetting revenue credit

of 10 percent to account for the resale of firm pipeline rights. Power Rates Study, BP-16-E-BPA-01, at 72. It is described as a revenue credit a utility would receive after it first incurred a fixed cost for the full pipeline capacity rights. The right to release pipeline capacity provides the utility an opportunity to generate revenue by reselling its pipeline capacity when the utility determines that the capacity is not needed for its own purposes. In fact, the amount of any available credit at any particular decision point becomes part of the determination of whether to generate or not, which is the very essence of a variable cost in this context. The revenue that is generated is both uncertain and occurs after a fixed cost is incurred. ICNU Br., BP-16-B-IN-01, at 6-7. This description comports with the definition of variable revenue and thus, pursuant to the TRM language, should not be included in the demand rate calculation. TRM, BP-12-A-03, at 76-77.

WPAG argues that BPA does not expressly identify the definition of “variable revenue” it relied on in classifying pipeline capacity release credits as variable revenue. WPAG Br. Ex., BP-16-R-WG-01, at 3. WPAG notes, however, that in the past BPA has used Black’s Law Dictionary to define terms. *Id.* at 4. For the sake of argument, the Black’s Law Dictionary definitions of fixed and variable costs provided by WPAG, *id.*, will be used to evaluate further whether pipeline capacity release revenue should be considered fixed or variable for purposes of calculating BPA’s demand rate. As quoted by WPAG, Black’s defines fixed cost as “[a] cost whose value does not fluctuate with changes in output of business activity ...” and variable cost as “[t]he cost that varies in the short run in close relationship with changes in output.” *Id.*, quoting Black’s Law Dictionary (10th Ed. 2014). WPAG suggests these concepts may be applied to revenues as well as costs.

WPAG states that BPA “appears to” suggest that variable revenue is revenue that occurs only after a fixed cost is incurred and also “seems to” suggest that if there is any uncertainty relating to the revenue, then it is variable revenue per se. WPAG Br. Ex., BP-16-R-WG-01, at 4. WPAG states that these apparent assumptions “do not comport with the definition of variable revenue.” *Id.* WPAG argues that the definition for revenues is identical to costs—it is not the potential for annual or monthly variability in revenue that makes it fixed or variable revenue, but rather whether such revenue is dependent on the production or operation of the plant. *Id.* at 5. As discussed further below, the operational dependency of available pipeline capacity can be used to determine the proper categorization of variable or fixed cost.

However, there is not always a bright dividing line between variable and fixed cost, and other factors must also be considered, such as the timeframe (short-run versus long-run) and nature of the variability, albeit not in this instance. Black’s Law Dictionary explicitly includes a timeline component in the definition of variable cost that also is applicable to variable revenue: “short run.” Moreover, the nature of the variability is also important because an asset financed with a fixed rate loan is no more a fixed cost than an asset financed with a variable rate loan. The debt service on both are certainly fixed costs despite the financial variability cause by differences in financing terms.

ICNU argues that release of pipeline capacity depends, like fuel costs, on the level of operation of the turbine and also depends on market conditions for short-term pipeline capacity. ICNU Br.,

BP-16-B-IN-01, at 6-7. Therefore, ICNU argues, pipeline capacity release revenue is variable and should not be included in the calculation of fixed costs. *Id.* at 7. WPAG suggests that this argument relies on the operations of the plant leading up to a determination to re-sell pipeline capacity rights as the basis for categorizing the revenue received from such sales as variable revenue, and that this assumption is wrong. WPAG Br. Ex., BP-16-R-WG-01, at 5. WPAG argues that the correct focus of the analysis is on the actual relationship of the revenue to the operations at the plant once the pipeline rights are resold. *Id.* WPAG’s argument, however, is flawed because it fails to recognize the operational dependency between the availability of fuel (available pipeline capacity to deliver fuel to the resource) and the resource’s operations. The decision to resell pipeline capacity directly dictates whether the plant can or cannot operate. This is because once the pipeline capacity is sold, the generating resource cannot use that pipeline capacity to transport fuel and cannot operate due to lack of fuel delivery. Conversely, the generating resource can transport fuel and generate only to the extent that its pipeline capacity is not sold. This close operational relationship comports with Black’s Law Dictionary’s definition of “variable” and also supports the conclusions reached by ICNU. Black’s definition of fixed cost further supports ICNU’s position in that it defines a fixed cost as a cost that does not fluctuate with business activity. The existence of revenue from the resale of pipeline capacity is the result of a utility’s evaluation and business decision to resell pipeline capacity when it is not needed for its own purposes—it is in “close relationship with changes in output.” If the utility takes no action, no pipeline capacity release revenue would be received. Conversely, a fixed cost persists regardless of whether or not the utility takes action regarding generation level, pipeline capacity release, or any other business decision.

WPAG argues that revenue from resale of pipeline capacity should be categorized as fixed rather than variable revenue because once pipeline capacity rights are resold the revenue received from such sales is “completely independent from (i) the operation of BPA’s proxy resource, (ii) the operation of any resource associated with the third party purchaser of the capacity rights, and/or (iii) the actual use of the sold capacity rights by the third party purchaser.” WPAG Br. Ex., BP-16-R-WG-01, at 5. WPAG claims that BPA receives the revenue regardless of any of those factors. *Id.* WPAG’s argument is not true. The decision to resell pipeline capacity dictates the operation of the resource and is not completely independent. As noted above, once pipeline capacity rights are resold, the resource cannot operate due to lack of fuel supply. If pipeline capacity resale revenue were completely independent from operation of the resource, as WPAG states, the resource would be capable of operating without fuel, which is an erroneous assumption.

WPAG argues that the analysis of whether pipeline capacity release revenue is fixed or variable should start with the resale rather than what happens prior to such sales. *Id.* at 6. WPAG states:

the amount of capacity required for the proxy resource for a given period is first identified based on forecasted need and plant operations. It is following that determination that the amount of capacity so determined would actually be acquired. Under those circumstances it is the purchase of capacity rights that creates the cost in the first instance and the subsequent independence of those costs from the operations of the plant following the acquisition that then fixes

them. The fact that the amount of pipeline capacity purchased was originally based on a forecast of plant operations is irrelevant as to whether the cost is fixed or not. If it were otherwise, the pipeline acquisition costs would be categorized as variable costs due to their dependency on the forecasted need and operations of the plant, and those costs could not then be included in the demand rate calculation under the TRM.

Similarly in this instance, it is the actual resale of capacity rights that creates the revenue credits and the independence of that revenue from plant operations and/or actual use of the capacity following the sale that places the credits squarely in the fixed revenue category. And, just like when the pipeline capacity is purchased, the forecasted plant operations that feed into the decision to resell or not resell the capacity is also irrelevant for purposes of determining whether the revenue is fixed or variable once the capacity is resold.

Id. The premise of WPAG’s foregoing argument is fundamentally flawed. The amount of pipeline capacity originally purchased is determined by the technical specifications of the resource. It is not, as WPAG asserts, determined by a forecast of plant operations. The amount of pipeline capacity required under the technical specification of the resource remains the same regardless of the amount of hours the resource operates. Therefore, the costs incurred to purchase pipeline capacity rights are a fixed cost.

WPAG argues that despite ICNU’s assertions to the contrary, the fact that at one point the Council characterized capacity release credits as a reduction in fixed cost but no longer uses this assumption for long-term planning purposes does not alter the above conclusion for purposes of calculating the demand rate under the TRM. *Id.* WPAG asserts that this is because the demand rate under the TRM is to be based on a *short-term* rather than *long-term* fixed cost computation. *Id.* at 6-7. WPAG notes that the TRM states that “BPA will base the Demand Rate on the *annual* fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process.” *Id.* at 7, *citing* TRM, BP-12-A-03, at 77 (emphasis by WPAG). WPAG notes that the TRM further provides that “BPA will identify the marginal capacity resource and the annual fixed costs associated with that resource *for each Rate Period.*” *Id.*, *citing* TRM, BP-12-A-03, at 78 (emphasis by WPAG). WPAG states that this language directs BPA to base the demand rate on the fixed costs incurred within each year of the rate period. *Id.* WPAG suggests that it should be expected that this annual snapshot of the fixed costs associated with an operating natural gas-fired generating resource can be different from those the Council includes in its long-term planning calculation. *Id.* WPAG notes that the Council also recognized in its Sixth Power Plan that “natural gas is supplied on a firm gas transportation contract *with capacity-release capability.*” *Id.*, *citing* BP-16-E-WG-02, at 21, *citing* Sixth Power Plan, at 6-36 (emphasis by WPAG). WPAG asserts that, accordingly, as recognized by the Council, capacity release credits are a cost component of a currently operating natural gas-fired generating resource, and for this reason it is more than reasonable to include such credits in the *short-term* fixed cost calculation for the demand rate under the TRM. *Id.*

WPAG is correct that the demand rate is not a long-term planning concept, which may warrant that the calculation of the demand rate be different from the calculation the Council includes in its long-term planning. However, WPAG also makes a distinction between long-term and short-term. In this instance, this is not a long-term versus short-term issue. Whether the period in question is one year, one rate period, or the full 20-year study the Council undertakes, given the close operational relationship included in the definition of variable cost cited above, capacity release credits must be thought of as variable. Close operational relationship aside, even from the shortest perspective of one year provided by WPAG, which is consistent with the TRM's reference to "annual fixed costs," treating capacity release credits as fixed would imply that the operator knows beforehand when the pipeline capacity would not be needed over the course of the coming year. This is not a realistic expectation given that the nature of a capacity resource is to help a utility mitigate the impacts of unpredictable events. A utility's determination that the pipeline capacity is not needed for its own purposes would be made much closer to the operating period than annually and thus should not be included for purposes of calculating the "annual" fixed costs. Concerning WPAG's citation of the Council's Sixth Power Plan at 6-36, it is undisputed that capacity-release capability is included in firm gas transportation contracts. This fact, however, does not change the arguments above.

Therefore, using Black's Law Dictionary's definition of fixed and variable costs, pipeline capacity release revenue credits are not a reduction to fixed costs due to anticipated fluctuations in value caused by utility business activity, but instead are a variable revenue due to their close relationship with the operation of the resource. Further, the hypothetical nature of the current resource is a critical consideration because it obscures the facts needed to prove or disprove the potential equity issue raised by WPAG. If the output of a capacity resource is purchased to serve load, BPA and its customers will have to evaluate the facts at that time and determine how best to apply the principle of cost causation.

Decision

BPA will not include a pipeline capacity release credit in the computation of the demand rate.

2.5.3 Load Growth Rate Billing Adjustment

The Load Growth Rate Billing Adjustment is designed to address a cost recovery and equity issue that became apparent when BPA was setting its BP-14 rates. Weekley *et al.*, BP-16-E-BPA-35, at 9; *see also* BP-14 ROD, BP-14-A-03, at 67. The issue concerns the allocation of costs of a BPA 5 aMW purchase of power stemming from BPA's obligations under the CHWM contracts.

Each Load Following customer had multiple options for serving its Above-RWHM Load. One of those options was to elect the Load Growth rate alternative. Under this rate alternative, a customer placed on BPA the obligation to serve its Above-RHWM Load at the Tier 2 Load Growth rate for the entire contract term, through FY 2028. Weekley *et al.*, BP-16-E-BPA-35, at 9-10.

More than 50 of BPA's customers elected this option. These customers became the Load Growth customers and are enumerated in Appendix B to the BP-16 Power Rate Schedules. Weekly *et al.*, BP-16-E-BPA-35, at 10. In response to this long-term commitment, and based on the expectation that the amount of Above-RHWM Load would grow over time, BPA purchased 5 aMW in 2011 (FY 2012) to serve these customers' Above-RHWM Load. *Id.*

After BPA made the 5 aMW purchase two factors changed. First, more recent projections of load growth of the Load Growth service customers are considerably less than the forecast at the time the purchase was made. *Id.* Most customers in the Load Growth customer pool currently have projected Above-RHWM loads of less than 1 aMW a year. Under the TRM, customers with less than 1 aMW (8,760 MWh) of Above-RHWM Load can receive service at the Load Shaping rate and not pay for the power at the Tier 2 Load Growth Rate. *Id.*; *see also* TRM, BP-12-A-03, at 54. For the BP-16 rate period, only one customer in the Load Growth pool has Above-RHWM Load in excess of 1 aMW in a year. Weekly *et al.*, BP-16-E-BPA-35, at 10. This customer has an Above-RHWM Load amount of about 1.1 aMW per year and will be charged for this load at the Tier 2 Load Growth Rate. *Id.* This leaves about 3.9 aMW of BPA's 5 aMW purchase to be remarketed. *Id.*

The second factor that has changed is the price of power. This factor is significant because the TRM directs that the portion of the 5 aMW purchase not needed for Load Growth service must be remarketed to other Tier 2 cost pools or, if necessary, applied to reduce system augmentation. *Id.* at 11; *see also* TRM, BP-12-A-03, at 26-28. This remarketing occurs at the current forecast of market prices and may result in either a debit or a credit to the Load Growth customer cost pool depending upon whether current prices are higher or lower than the original acquisition price. Weekly *et al.*, BP-16-E-BPA-35, at 11. The prevailing market price for power today is substantially less than the price BPA paid for the 5 aMW acquisition in 2011, resulting in a financial shortfall. *Id.* The shortfall is \$516,489 in FY 2016 and \$575,371 in FY 2017. Power Rates Study Documentation, BP-16-FS-BPA-01A, Table 3.14.

To recover the shortfall between the purchase price paid and the remarketing value in BP-14 rates, BPA instituted the Load Growth Rate Billing Adjustment paid by Load Growth customers with Above-RHWM Load greater than zero but less than 8,760 MWh. Staff proposes to continue using the Load Growth Rate Billing Adjustment for BP-16 rates.

Issue 2.5.3.1

Whether BPA should adopt the Load Growth Rate Billing Adjustment to recover the financial shortfall from customers that elected the Tier 2 Load Growth service and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate.

Parties' Positions

WPAG objects to Staff's proposal to use the Load Growth Rate Billing Adjustment to recover the cost of the shortfall. WPAG Br., BP-16-B-WG-01, at 34. WPAG argues that assigning these

costs to customers that are not purchasing power at a Tier 2 rate is contrary to the terms of the TRM. *Id.*

WPAG proposes that BPA defer recovering the shortfall, with interest, until the end of FY 2024, at which point more customers may be purchasing power at the Tier 2 Load Growth rate. *Id.* at 38. WPAG proposes that if BPA is still unable to recover the shortfall by the end of FY 2024 BPA should recover these costs by assigning them to the Composite cost pool. *Id.*

BPA Staff's Position

Only one customer is purchasing power at the Tier 2 Load Growth rate, and it would be inequitable to require this single customer to shoulder the entire burden of the shortfall. Weekley *et al.*, BP-16-E-BPA-35, at 12. Staff recommends that the shortfall be allocated, through the Load Growth Rate Billing Adjustment, to the customers that elected the Load Growth service option and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate. *Id.* at 18.

Evaluation of Positions

As noted above, only one customer will purchase power at the Tier 2 Load Growth rate in the BP-16 rate period. Allocating the entire shortfall to the Tier 2 Load Growth rate in this case would burden this single customer with \$1,091,860 (updated pursuant to the BP-16 final studies: Power Rates Study Documentation, BP-16-FS-BPA-01A, Table 3.14) in additional costs for the rate period. Weekley *et al.*, BP-16-E-BPA-35, at 11. Staff does not consider it consistent with equity or cost causation principles to assign the entire shortfall for the 5 aMW purchase to the single customer purchasing power (1.1 aMW) at the Tier 2 Load Growth rate. *Id.* at 10-11. This customer will pay its proportionate share (about 20 percent) of the costs of the 5 aMW purchase through the application of the Load Growth rate, which results in a Load Growth rate for this customer of \$45.18/ MWh in FY 2016 and \$49.60/ MWh in FY 2017. *Id.* at 11; *see also* BP-16 Power Rate Schedules at 11-12.

Staff proposes, instead, to recover the \$1,091,860 shortfall by allocating these costs to the other customers that elected the Load Growth service and have Above-RHWM load but do not presently pay the Tier 2 Load Growth rate because their Above-RHWM load is less than 1 aMW. Weekley *et al.*, BP-16-E-BPA-35, at 11-12; *see also* TRM, BP-12-A-03, at 54, and Power Rates Study Documentation, BP-16-FS-BPA-01A, Table 3.14. This alternative is reasonable because these customers elected the Load Growth service, have Above-RHWM load need that is not eligible for service at Tier 1 rates, and benefit from the 5 aMW purchase because it reduces their exposure to market volatility. Weekley *et al.*, BP-16-E-BPA-35, at 11-14.

WPAG agrees that allocating the entire shortfall to the Tier 2 Load Growth rate would be inequitable because only a single customer is purchasing power at that rate; however, WPAG argues that Staff's proposal is contrary to the terms of the TRM. WPAG Br., BP-16-B-WG-01, at 38. Specifically, WPAG argues that section 3.4 of the TRM requires that the shortfall from the 5 aMW purchase be recovered from the Tier 2 cost pool for which the power was acquired, which in this case would be the Load Growth cost pool. *Id.* at 34-35. WPAG argues, however,

that BPA may recover costs from the Load Growth cost pool only through the application of a Tier 2 rate for “power purchased under a CHWM Contract to meet a customer’s Above-RHWM load.” *Id.* at 35. Citing various definitions in the TRM, WPAG maintains that Staff’s proposal violates this construct by assessing the Load Growth Rate Billing Adjustment to the Load Shaping rate, which WPAG contends is a sale of power at a Tier 1 power rate, not a Tier 2 rate. *Id.* at 36. WPAG concludes that the better approach is to defer recovering the shortfall until the end of FY 2024, when it is more likely that other customers will be purchasing power at the Tier 2 Load Growth rate. Saleba *et al.*, BP-16-E-WG-01, at 23.

Staff and WPAG are in alignment on certain aspects of this issue. For instance, Staff does not disagree with WPAG’s assessment that under the normal course of the TRM implementation, the default means of collecting the total contract cost would be through the application of the Tier 2 Load Growth rate. Weekley *et al.*, BP-16-E-BPA-35, at 13. In addition, WPAG agrees with Staff’s assessment that following the default operation of the TRM in this instance would be unreasonable. WPAG Br., BP-16-B-WG-01, at 38. Finally, WPAG does not disagree with Staff’s finding that the 5 aMW purchase was originally made to meet the needs of the Load Growth service group and that the costs of this purchase are properly allocable to the Load Growth cost pool. Saleba *et al.*, BP-16-E-WG-01, at 17. Where Staff and WPAG differ is on selecting the alternative *means* for recovering the shortfall from the Load Growth customers.

Staff’s proposal recovers the shortfall as it is realized from the Load Growth rate pool customers by applying a billing adjustment to Load Growth customers that have Above-RHWM load greater than zero and less than 8,760 MWh. Weekley *et al.*, BP-16-E-BPA-35, at 11-12, *citing* Stiffler *et al.*, BP-16-E-BPA-17, at 4-7. These customers technically have load subject to Tier 2 rates (and therefore would be subject to the Tier 2 Load Growth rate) but the TRM permits these customers to serve this load using the Load Shaping rate because the load is projected to be under 8,760 MWh. Weekley *et al.*, BP-16-E-BPA-35, at 11-12, 15.

WPAG argues that this proposal violates the TRM because, in WPAG’s view, the only means BPA has of recovering Tier 2 costs (and hence the shortfall) is through the sale of power to a customer at a Tier 2 rate. In this case, WPAG contends, the Load Growth customers are not purchasing power from BPA at a Tier 2 rate but purchasing power at the Load Shaping rate, which is a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 35-36. For support, WPAG points to the definitions of Tier 2 Costs, Tier 2 Cost Pool, Tier 2 Rate, and the TRM provisions governing the Load Shaping Rate. *Id.*

Contrary to WPAG’s claims, Staff’s proposal does not run afoul of the terms of the TRM. The terms Tier 2 Costs, Tier 2 Cost Pool, and Tier 2 Rate are defined as follows:

- “Tier 2 Costs” are the expenses and revenue credits that BPA will identify on [TRM] Table 2 and allocate to the appropriate Tier 2 Cost Pool during the applicable 7(i) Process.
- “Tier 2 Cost Pools” means all of the Cost Pools to which Tier 2 Costs will be allocated by BPA.

- “Tier 2 Rate” means any Priority Firm Power (PF) rate that reflects Tier 2 Costs and applies to power purchased under a CHWM Contract to meet a customer’s Above-RHWM Load.

TRM, BP-12-A-03, at xxiv-xxv.

A related term not mentioned by WPAG but relevant here is the term “Cost Pool,” which is defined as follows:

- “Cost Pool” means a grouping of expenses and revenue credits allocated to a specific product, service, or customer type.

Id. at xi.

Staff’s proposal is consistent with these definitions. First, the Load Growth service customers have purchased a specific product from BPA (Load Growth service), BPA has incurred costs to provide this service (5 aMW purchase), and BPA is allocating these costs to this group in the BP-16 rates. PRS Documentation, BP-16-FS-BPA-01A, Table 3.10. Second, the costs BPA is allocating to these Load Growth service customers are Tier 2 costs. This is the case because the costs being allocated to the Load Growth cost pool were incurred to meet these customers’ Above-RHWM load (load not eligible for service at Tier 1 rates). Weekley *et al.*, BP-16-E-BPA-35, at 13. Finally, Staff proposes to apply a “Tier 2 Rate” to the Load Growth customer group; the Load Growth Rate Billing adjustment is a Tier 2 rate because it reflects Tier 2 costs and applies to power purchased under a CHWM contract for Above-RHWM load.

WPAG objects to this interpretation, arguing that these customers are purchasing power at the Load Shaping rate, which WPAG claims is a Tier 1 rate, not a Tier 2 rate. WPAG Br., BP-16-B-WG-01, at 36-37. WPAG claims BPA’s rate schedule and the TRM identify the Load Shaping rate as a Tier 1 rate without reference to whether the power being sold at the Load Shaping rate is for Above-RHWM Load, and therefore, the Load Shaping rate is always a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 36.

WPAG’s argument, however, confuses the issue. The TRM permits a customer’s Above-RHWM load to be served at the Load Shaping rate (when less than 8,760 MWh); the application of the Load Shaping rate to this load, however, does not transform this Above-RHWM load to Tier 1 service or preclude BPA from allocating appropriate Tier 2 costs to customers with Above-RHWM load.

In effect, the Load Growth Rate Billing Adjustment functions as a customer charge applicable to customers with Above-RHWM load. A customer charge is a frequently used component of rate design, and the TRM is clear that rate design for BPA’s Tier 2 rate alternatives will be determined in 7(i) processes. TRM, BP-12-A-03, at 79. The customer charge proposed by Staff reflects Tier 2 costs and applies to power purchased under a CHWM contract to meet a Load Growth customer’s Above-RHWM load. This is exactly the definition of a Tier 2 rate in the TRM. *Id.* at xxv. The application of any other rate to the customer’s Above-RHWM load, Load Shaping or otherwise, is irrelevant.

To clarify the intent and result of the Load Growth Rate Billing Adjustment, BPA will rename it the Load Growth Rate Customer Charge. Further, BPA will add a section to the Tier 2 rate schedules that clarifies that the Load Shaping rates are Tier 2 rates when applied to a customer's Above-RHWM load served by BPA. The modified Tier 2 rate schedule will be:

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to section 4.3 of the Tiered Rate Methodology, BP-12-A-03, the Tier 2 Load Shaping charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates

The Tier 2 Load Shaping Rates shall be the rates specified in section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant

The Tier 2 Load Shaping billing determinant for each billing period is incorporated into the billing determinant established in section 2.1.3.2.

[The former section 2.2.1, Short-Term Charge, and subsequent sections will be renumbered accordingly.]

* * * *

2.2.3 Load Growth Charge

* * * *

2.2.3.3 Load Growth Rate ~~Billing Adjustment~~ Customer Charge

Load Growth Rate Customers are subject to a ~~billing adjustment~~ customer charge for FY 2016 and FY 2017.

The ~~adjustment~~ monthly amounts ~~for~~ charged to each Customer are set forth in Appendix B to the General Rate Schedule Provisions.

WPAG also appears to contend that because the Load Growth customers are paying for their Above-RHWM load at the Load Shaping rate, these customers are now insulated from being allocated Tier 2 costs associated with their Above-RHWM load. WPAG reaches this conclusion because it thinks the Load Shaping rate is a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 36-37. This is incorrect. When the Load Shaping rate is used to charge for power used to serve Above-RHWM load it is a Tier 2 rate. It meets each element of the definition of Tier 2 rate in the TRM: (1) it is a PF rate; (2) it reflects Tier 2 costs; (3) it is purchased under a CHWM contract; and (4) it is applied to power that meets a customer's Above-RHWM load. TRM, BP-12-A-03, at xxv. That the Load Shaping rate is a Tier 2 rate in this context can also be seen from several aspects of the Load Shaping rate design. First, the Load Shaping rate is a market-based rate that, pursuant to the TRM, is set equal to BPA's forecast of market prices during the rate period. *Id.*

at 64. Thus, unlike Tier 1 rates that are set to recover the cost of BPA's existing system, the Load Shaping rate is set equal to the forecast cost BPA will incur to purchase additional power in the market to serve a customer's Above-RHWM load. Second, the Load Shaping charge is subject to a true-up at the end of each year "to avoid charging or crediting the market-based Load Shaping rate for energy within the customer's RHWM." *Id.* at 65. In other words, the Load Shaping rate must be adjusted to a different level if it is applied to power purchased under Tier 1 rates. It remains unadjusted through the true-up to the extent that the power purchased is in excess of the customer's RHWM. Third, the TRM makes clear that the Tier 1 rates apply to only a customer's RHWM load, *not* a customer's Above-RHWM load. The RHWM is defined as:

the amount, calculated by BPA in each RHWM Process pursuant to the formula in section 4.2.1 and expressed in average megawatts, that BPA establishes for each customer based on the customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a customer may purchase under Tier 1 Rates each Fiscal Year of the Rate Period is equal to the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.

Id. at xix (emphasis added).

As the above-quoted language makes clear, a customer cannot receive service for its Above-RHWM load at a Tier 1 rate because the "maximum planned amount of power a customer may purchase under Tier 1 Rates ... is equal to the RHWM for Load Following customers[.]" Consequently, when Load Following customers (such as those purchasing Load Growth service) receive power service for their Above-RHWM load at the Load Shaping rate, the transaction is made pursuant to a rate that is *not* a Tier 1 rate. Thus, the only remaining alternative is a Tier 2 rate. The TRM did not deem, as WPAG argues, that Above-RHWM load less than 8,760 MWh is eligible for service at Tier 1 rates, as that would be prohibited by the TRM's definition of RHWM. Rather, the TRM uses the market-based Load Shaping rates as a substitute for a cost-based Tier 2 rate when a Load Following customer's Above-RHWM load is less than 8,760 MWh.

WPAG's citations to various provisions of the TRM and BPA's rate schedules, WPAG Br., BP-16-B-WG-01, at 36-37, also do not support its claim that the Load Shaping rate is a Tier 1 rate when applied to Above-RHWM load. TRM section 5.2 states that the Load Shaping charges are "designed to recover costs associated with *shaping* the Tier 1 System Capability to the Monthly/Diurnal shape of a customer's Actual Monthly/Diurnal Tier 1 Load." TRM, BP-12-A-03, § 5.2 (emphasis added). This section, however, does not state that the Load Shaping rate is a Tier 1 rate, but rather a separate rate that is designed to recover costs associated with *shaping* the Tier 1 purchases of Load Following customers. Indeed, the TRM differentiates between rates that are Tier 1 rates and rates that are used to provide tertiary services for Tier 1 service (such as the Load Shaping rate). Later provisions of this same section of the TRM make this point clear. TRM section 5.2.4 establishes an elaborate true-up mechanism, which is intended "to avoid charging or crediting *the market-based Load Shaping Rate* for energy *within the customer's RHWM.*" TRM, BP-12-A-03, at 65 (emphasis added). The true-up applies so that a customer

neither pays for nor receives credits associated with the Load Shaping rates for load *within* its RHW (i.e., load subject to Tier 1 rates). This “true-up,” however, applies only to the extent that “a Load Following customer’s TOCA Load or Actual Annual Tier 1 Load is *less than* its RHW.” *Id.* (emphasis added). Customers with Above-RHW load are not subject to this true-up and are left to pay costs (or receive credits) associated with the market-based Load Shaping rate. *Id.*

WPAG notes that TRM Table 2.D allocates both the costs of serving load at the Load Shaping rate (i.e., the cost of Balancing Power Purchases) and the credits from the Load Shaping rate to Tier 1’s Non-Slice pool. Thus, WPAG claims, because costs and credits related to the Load Shaping rate are allocated to a Tier 1 cost pool, that rate is a Tier 1 rate under the TRM. WPAG Br., BP-16-B-WG-01, at 36. This is incorrect. There is no linkage between the effective rate type and the allocation of the revenue received from that rate. DSI revenue, RSS revenue, New Resource revenue, FPS revenue, and secondary sales revenue are all allocated to Tier 1 cost pools, but none of this revenue is generated from Tier 1 rates. PRS Documentation, BP-16-FS-BPA-01A, at 75-76. Further, some of the revenue generated from Tier 2 rates is explicitly allocated to both the Composite cost pool and the Non-Slice cost pool, specifically the Tier 2 Overhead Adder, Tier 2 Risk Adder (if applicable), and Tier 2 RSS revenue. *Id.* This crediting occurs because the cost of providing these non-Tier 1 services is allocated to the Composite cost pool, and the crediting ensures that Tier 1 customers are not paying the costs of such services.

WPAG also argues that even if the Load Shaping rate is a Tier 2 rate when applied to Above-RHW load, it would be a rate associated with a Tier 2 cost pool separate from the Load Growth customer cost pool. WPAG Br., BP-16-B-WG-01, at 37. Again, WPAG misses the issue. The Load Growth Rate Customer Charge recovers costs incurred on behalf of Load Growth customers that are undisputedly allocable to the Load Growth cost pool. There is no reason, semantic or otherwise, to create a new cost pool to recover these costs. In fact, it would needlessly complicate the issue as the new cost pool would be associated with the same customers that are responsible for the Load Growth cost pool. It is undisputed that the financial shortfall is associated with, and thus should be allocated to, the Load Growth cost pool. Staff proposes to recover the Load Growth cost pool’s shortfall through a fixed cost charge that is applicable to customers that elected service at BPA’s Tier 2 Load Growth rate alternative.

WPAG claims that the TRM constrains the Administrator’s ratemaking authority to recover Tier 2-related costs only through actual purchases of power at a Tier 2 rate. This, WPAG asserts, “gets to the heart of WPAG’s concerns[.]” WPAG Br., BP-16-B-WG-01, at 37. In WPAG’s view, if a customer is not purchasing power from BPA at a Tier 2 rate, the TRM prohibits BPA from developing a rate mechanism to recover Tier 2 costs from that customer. *Id.*

As described above, Staff’s proposal meets both the letter and the intent of the TRM and is not prohibited by its terms. Nonetheless, even if Staff’s proposal were to fail WPAG’s restrictive interpretation of the TRM, BPA would be well within its authority to adopt Staff’s proposal. The TRM does not prohibit BPA from adopting other rate mechanisms that ensure Tier 2 costs are recovered from the customers that caused BPA to incur the cost. TRM, BP-12-A-03, at 79-80. A number of TRM provisions make this clear.

First, the TRM is clear that Tier 2 rate design issues are left to BPA's discretion and determined in a section 7(i) process. Section 6 of the TRM states: "Consistent with the provisions below, the specific rate designs for BPA's Tier 2 Rate Alternatives will be determined in 7(i) Processes." TRM, BP-12-A-03, at 79. The Tier 2 Load Growth Rate Customer Charge is a rate design component of a "Tier 2 Rate Alternative" and, consequently, the design of this rate is left to BPA's discretion. *Id.* In this case, BPA has determined that the most appropriate rate design for recovering the costs of the 5 aMW purchase from the Load Growth customer cost pool is through two rate mechanisms: (1) the Tier 2 Load Growth rate, which assesses a proportional share of the costs of the 5 aMW purchase to the single customer that is purchasing power from BPA; and (2) the Load Growth Rate Customer Charge, which assesses the remaining shortfall to the customers that elected the Load Growth service option and have Above-RHWM load but are purchasing such power at the Load Shaping rate.

Second, the TRM expressly permits BPA to adopt a "Tier 2 Rate Alternative," which is defined as a "rate option established by BPA in a 7(i) Process for a customer with a CHWM Contract that elects to purchase power from BPA to serve its Above-RHWM Load." TRM, BP-12-A-03, at xxv. TRM section 6.1 confirms that BPA may propose new Tier 2 rate alternative constructs in a rate case: "BPA may propose in any 7(i) Process to add Tier 2 Rate Alternatives." TRM, BP-12-A-03, at 79. The Load Growth Rate Customer Charge is such an alternative. It is a rate established by BPA in a section 7(i) process for customers with a CHWM contract that elected to purchase power from BPA to serve their Above-RHWM load. Weekley *et al.*, BP-16-E-BPA-35, at 15. Although this rate is not based on the full cost of the power purchased to serve Load Growth customers' Above-RHWM load, nothing in the TRM requires that Tier 2 rate alternatives be so limited. The TRM directs BPA to recover certain costs from various cost pools but leaves it to BPA to determine through the rate case process how best to structure its rates to recover these costs. In this case, the Load Growth Rate Customer Charge is acting as a reservation or availability charge, essentially recovering costs from customers that elected BPA to provide a stand-ready service. *Id.*

Establishing the Load Growth Rate Customer Charge as a Tier 2 rate alternative is also consistent with the TRM's cost recovery direction. Section 6 of the TRM requires BPA to allocate Tier 2 costs and design its Tier 2 rates such that they "to the maximum extent possible" recover the "full allocated cost of BPA service to planned Above-RHWM Load." TRM, BP-12-A-03, at 79. The Load Growth Rate Customer Charge does just this. It ensures that the cost of standing ready to provide Load Growth service is allocated to the Tier 2 cost pool of the customers that elected this service. The TRM also directs that the Tier 1 system not subsidize service for Tier 2 customers. *Id.* ("The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.") Here again, the Load Growth Rate Customer Charge follows the TRM by ensuring the costs of the shortfall do not remain uncollected costs but are recovered from Load Growth customers that have Above-RHWM load.

Third, the Load Growth Rate Customer Charge is also consistent with the Administrator's discretion to develop risk mitigation measures for the Tier 2 Load Growth rate. The TRM provides the Administrator with broad discretion to develop tools to mitigate risk associated with

providing Tier 2 service. TRM section 9.2 provides: “Risks in Tier 2 will be assessed in each 7(i) Process both for each Tier 2 Rate Alternative and collectively for all Tier 2 Rate Alternatives to determine if the terms and conditions have mitigated such risks sufficiently to meet BPA’s risk standards.” TRM, BP-12-A-03, § 9.2. The specific mitigation tools BPA may develop to address the risk of providing Tier 2 rate alternatives are left to the Administrator’s discretion in each rate case:

In each 7(i) Process, when there is more specificity about the resource and purchase costs allocated to the various Tier 2 Cost Pools, BPA will assess the risks of providing service at the various Tier 2 Rate Alternatives. BPA will propose risk mitigation tools for each Tier 2 Cost Pool (e.g., planned net revenues for risk, cost recovery adjustment clauses, true-ups to actual costs). . . .

TRM, BP-12-A-03, § 9.2. Nothing in TRM section 9.2 limits BPA to developing risk tools such that they apply only to actual purchases of power at a Tier 2 rate. Rather, the TRM is clear that these mitigation tools apply “for each Tier 2 Cost Pool,” which may be mitigated by whatever means BPA determines is reasonable. The TRM does not specify, nor preclude, Staff’s proposed method for recovering these costs from Load Growth customers and thus leaves it to BPA’s discretion to develop methods other than a sale of power, such as with a customer charge, reservation fee, stranded-cost fee, and/or true-up charge. Weekley *et al.*, BP-16-E-BPA-35, at 14.

Fourth, the TRM expressly permits BPA to recover Tier 2 costs from rates other than Tier 2 rates only “when necessary to ensure BPA’s cost recovery during a Rate Period” TRM, BP-12-A-03, at 3. In this case, it is necessary for BPA to use the proposed adjustment mechanism to recover the costs of the 5 aMW acquisition from the appropriate customers. Weekley *et al.*, BP-16-E-BPA-35, at 15-16. If BPA included all of the costs of the 5 aMW purchase in the Load Growth rate, the single customer purchasing at that rate would be unfairly burdened with the entire purchase, which would not be equitable. *Id.* at 16. But, if BPA does nothing at this time, it would not be taking steps to ensure BPA’s cost recovery during the rate period. *Id.* Staff’s proposal strikes the proper balance between these two extremes: it ensures BPA timely recovers its costs, but it does so in a way that does not inequitably burden one customer when the cost was incurred to protect all Load Growth customers from market volatility. *Id.* at 14 & 16.

Fifth, WPAG’s interpretation would also hinder BPA’s ability to mitigate market risk and take reasonable actions to provide power service to its customers. This is particularly true for the Load Growth rate option because it is a rate for service where customers elected for BPA to manage the cost of power to the collective power need of all Load Growth customers. Weekley *et al.*, BP-16-E-BPA-35, at 13; Regional Dialogue Guidebook,² at 33 (“BPA manages resource acquisitions to meet the Above-RHWM loads of customers in this cost pool and melds the costs of these resource acquisitions into the cost pool over time.”). There are several ways to balance purchase price risk and manage an unknown portfolio power need, such as through

² The Regional Dialogue Guidebook, *Background on Products, Rates, and Resource Support Services Available to BPA’s Public Utilities*, updated June 4, 2010, available at http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/2010-06-04_RDproductsratesguidebook_Revised.pdf.

different power purchase strategies (long-term versus short-term purchases) as well as through financial options (such as the right to buy power at a set price). Weekley *et al.*, BP-16-E-BPA-35, at 14. While BPA decided to buy a certain amount of power to reduce the Load Growth rate pool's exposure to market volatility, nothing precluded BPA from purchasing an option to reduce exposure to market volatility. *Id.* Had BPA used an option instead of the long-term purchase, a cost would have been incurred to protect Load Growth customers but no physical power purchase would have been made. *Id.* In that case, cost recovery responsibility would clearly belong to the Load Growth customer cost pool and would require that BPA adopt a rate mechanism other than the per-unit Load Growth rate to collect these costs, similar to, or exactly the same as, the Load Growth Rate Customer Charge. *Id.* No language in the TRM prohibits BPA from recovering the costs of these market mitigation strategies from the Load Growth customers. Nor is there any indication that these costs are uncollectable under the TRM from Tier 2 customers simply because the option would not result in the sale of power to these customers at a Tier 2 rate.

For these reasons, Staff's proposal is consistent with the terms of the TRM and within the discretion afforded to BPA under the TRM.

WPAG claims, however, that it has a better solution to the shortfall; one that, it claims, is "more consistent" with the TRM. WPAG Br., BP-16-B-WG-01, at 38. To be clear, WPAG does not recommend that BPA apply the default method for recovering these costs from the Load Growth customer cost pool. *Id.* Instead, WPAG proposes to defer the recovery of these costs until the end of FY 2024, when WPAG thinks there will be more customers purchasing power at the Tier 2 Load Growth rate. *Id.* To ensure that no customers are financially harmed by such deferral, WPAG suggests that interest be applied to the outstanding balance. Saleba *et al.*, BP-16-E-WG-01, at 22. WPAG claims this proposal is "more consistent with the language of the TRM, and does not attempt to collect these costs from customers who are not purchasing power during the rate period under the Load Growth Rate." WPAG Br., BP-16-B-WG-01, at 38.

WPAG's claim that Staff's proposal is inconsistent with the TRM is wrong for the reasons described above. But more importantly, BPA need not determine which proposal is "more consistent" with the default method for recovering Tier 2 costs (a method neither Staff nor WPAG supports applying in this case) to decide this issue; rather, the question is whether either alternative is permissible under the TRM, and if they both are, which BPA should adopt.

WPAG claims its proposal is superior because it follows more closely the letter of the TRM, but on this front WPAG is incorrect. WPAG readily acknowledges that its proposal does not ensure recovery of the costs of the shortfall and argues that in the unlikely event that future load growth does not materialize "BPA should reallocate these costs to the Composite Cost Pool pursuant to the terms of the TRM." WPAG Br., BP-16-B-WG-01, at 38. The TRM, however, does not support a "wait and see" approach to recovering Tier 2 costs. Instead, the TRM places on BPA an affirmative obligation to take reasonable actions to avoid a reallocation of costs from the Tier 2 cost pool to the Tier 1 rates. For instance, the TRM provides:

This TRM specifies how PF rates will be developed by BPA to ensure, *to the maximum extent possible*, that Tier 1 Rates do not include costs of serving Publics' Above-RHWM Load.

* * * *

The allocation of Tier 2 Costs and the design of Tier 2 Rates will ensure to the maximum extent possible that the Tier 2 Rates will recover the full allocated cost of BPA service to planned Above-RHWM Load. The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.

TRM, BP-12-A-03, at 1, 79 (emphasis added).

In addition, section 2.6 of the TRM provides that before BPA reallocates costs from the Tier 2 cost pool to any Tier 1 cost pool BPA must, among other actions,

make reasonable efforts to recover the costs from the party(s) that would otherwise be responsible for such costs. Such efforts may include making demand on any available credit support and pursuing legal action when BPA determines it is appropriate.

Id. at 10.

Taken together, these provisions make clear that BPA must “to the maximum extent possible” set its rates to recover costs allocated to the Tier 2 cost pool from customers with Above-RHWM load, and such recovery may be assigned to “the party(s) that would otherwise be responsible for such costs.” Weekley *et al.*, BP-16-E-BPA-35, at 18. Deferring these costs to future rate periods in the hope that a future generation of Load Growth customers might pay these costs through the explicit Tier 2 rate, as WPAG suggests, is not consistent with the affirmative steps BPA is expected to take to ensure these costs are recovered from Tier 2 ratepayers. *Id.*

WPAG responds that these provisions “do not eliminate the TRM requirement that the applicable Tier 2 Rate(s) can only be applied to those customers actually purchasing power from the applicable Tier 2 Cost Pool.” WPAG Br., BP-16-B-WG-01, at 39. WPAG concurs that BPA must take reasonable steps to recover Tier 2 costs, but WPAG asserts these steps are limited to selling power at Tier 2 rates. *Id.*

WPAG’s reading of the TRM, however, is inconsistent with its language and would nullify BPA’s ability to properly protect Tier 1 customers from Tier 2 costs. TRM section 2.6 is clear that BPA must make “reasonable efforts” to recover costs from the parties responsible for those costs. Nowhere in the TRM is this general obligation limited only to selling power at a Tier 2 rate. Indeed, if that were BPA’s only means of recovering Tier 2 costs, then this section would have no meaning—the only “reasonable effort” BPA could take to recover these costs would be to sell more power at Tier 2 rates.

WPAG's restrictive reading of the TRM would also lead to an unreasonable limitation on BPA's ability to recover its costs from appropriate cost pools. In effect, WPAG contends that if BPA did not have a single customer purchasing power at the Tier 2 Load Growth rate, BPA would have no means of recovering these costs from the Load Growth customers. The shortfall would then have to be allocated to the Composite cost pool and be borne by *all* of BPA's power customers, even though it is undisputed that these costs were incurred for the benefit of the Load Growth customers alone. This outcome is contrary to the TRM's main principles that costs are allocated to the customers that benefit from the costs and that Tier 1 rates be protected from subsidizing Tier 2 cost pools:

This TRM specifies how PF rates will be developed by BPA to ensure, to the maximum extent possible, that Tier 1 Rates do not include costs of serving Publics' Above-RHWM Load.

TRM, BP-12-A-03, at 1. The TRM also states:

Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefits from such costs.

Tier 1 Costs will be kept separate and distinct from Tier 2 Costs. Tier 1 Costs will be recovered through the Tier 1 Rates. Tier 2 Costs will be recovered through Tier 2 Rates, except when necessary to ensure BPA's cost recovery during a Rate Period.

BPA will seek to recover all costs of the applicable Tier 2 Cost Pool from customers purchasing power from that Tier 2 Cost Pool before proposing any reallocation of costs to the Composite Cost Pool.

Id. at 3. The TRM notes:

[C]osts and benefits of the sale of or inability to sell excess electric power allocated under section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources that generate such excess electric power are allocated.

Id. at 4. The TRM requires that:

The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.

Id. at 79.

Staff's proposal avoids this unreasonable outcome because it recognizes that BPA has the authority to design its rates to ensure that costs are properly assigned to the cost pools that

caused BPA to incur the costs (the Load Growth customer cost pool) and protects the Tier 1 cost pool from subsidizing other cost pools. This is a clear application of basic cost causation principles.

WPAG's proposal also contravenes basic ratemaking principles. In effect, WPAG's proposal would have BPA burden future ratepayers with acquisition decisions made in 2011 (FY 2012), with the resulting costs incurred in FY 2016-2017, even though by the time these costs are ultimately included in rates (FY 2024) the underlying 5 aMW acquisition will have long expired. Weekley *et al.*, BP-16-E-BPA-36, at 17. Future ratepayers would then not only have to pay for the acquisitions used to serve their own loads under the Tier 2 Load Growth rate but would also have to pay the costs (as well as any interest) of the acquisitions that were delivered more than five years earlier. *See id.* While deferring costs between rate periods may be prudent in some circumstances, BPA can find no reason to ignore basic cost causation and general ratemaking principles to intentionally shift a cost to future ratepayers if there is a viable means available to recover such costs from the customers that caused BPA to incur the costs. This is especially true given the speculative amount of Tier 2 Load Growth sales that will be present in FY 2024; there is no guarantee that incorporating the costs of this purchase with the cost of purchases to serve such loads in FY 2024 will result in a rate that those customers will be able to shoulder.

Furthermore, WPAG's proposal to shift the costs to the Composite cost pool if there is insufficient Load Growth rate pool load in FY 2024 does not work. Shifting costs from a Tier 2 cost pool to the Composite cost pool is an option only when all other options are exhausted. In the event there is insufficient load purchasing power under the Tier 2 Load Growth rate at that time, there still remains the option to use this same adjustment mechanism. Tier 1 customers would rightfully object to using the Composite cost pool as the fallback source of revenues when a viable alternative such as Staff's proposed adjustment is available.

Finally, WPAG's proposal violates BPA's accounting policies. BPA's Accounting for Regulatory Assets and Liabilities Policy (Accounting Policy), which is based on Financial Accounting Standards Board, Accounting Standards Codification 980, Regulated Operations, requires that costs incurred must be recoverable through rates for the regulated services or products. Weekley *et al.*, BP-16-E-BPA-35, at 18. Deferring the costs in the manner proposed by WPAG is inconsistent with this policy. *Id.* While the Accounting Policy allows for certain costs to be deferred, such deferrals would be done on a case-by-case basis and are reserved for large (generally greater than \$5 million), unexpected, one-time expenditures. *Id.*

The stranded costs associated with the Load Growth rate do not fit these requirements. *Id.* The costs at issue are relatively small (\$1,091,860) when compared to costs typically eligible for deferral. The costs are not unexpected because they are known now, have occurred previously, and can be calculated with relative precision as part of the normal rate case process. Finally, the costs are not "one-time" expenditures. These costs have already shown up in two rate cases, and it is entirely possible that they may occur in the next rate case if Load Growth customers' loads do not grow and market prices remain at their current levels.

WPAG contends that, even if its proposal violates BPA's Accounting Policy, BPA should adopt it because its proposal is consistent with the TRM, while Staff's proposal is not. WPAG Br., BP-16-B-WG-01, at 39. WPAG asserts that if WPAG's proposal violates BPA's Accounting Policy, then the TRM provides that the ratemaking allocations determined in accordance with the TRM are to govern BPA's ratemaking. *Id.* Accordingly, WPAG claims, if there is a conflict between its proposal and BPA's Accounting Policy, WPAG's proposal should control. *Id.* at 40.

WPAG's reasoning is faulty. BPA's Accounting Policy is subservient to the terms of the TRM only in circumstances where the TRM's treatment of any cost or revenue is in conflict with BPA's Accounting Policy. TRM, BP-12-A-03, at 3. Here, however, WPAG has failed to establish that its proposal to defer costs is founded on the express terms of the TRM. Much like Staff's proposal, WPAG's proposal is an alternative means of recovering the shortfall from the Load Growth customer cost pool. Because the TRM does not directly speak to WPAG's proposal, BPA's Accounting Policy remains relevant in determining whether the treatment proposed by WPAG is reasonable. As described above, that treatment is not.

The better option in this case is Staff's proposal, which is consistent with the TRM and BPA's Accounting Policy. Weekley *et al.*, BP-16-E-BPA-35, at 20. The Load Growth Rate Customer Charge is a Tier 2 rate, whether viewed as a component of the charge assessed for customers purchasing power at Load Shaping rates for their Above-RHWM load or as a Tier 2 Alternative reservation charge for Tier 2 Load Growth service. In addition, Staff's proposal follows the TRM's directive that BPA take actions to recover Tier 2 cost pool costs from the customers that caused BPA to incur the costs. Finally, Staff's proposal does not require BPA to change or otherwise violate BPA's Accounting Policy, recovers these costs from current ratepayers, and ensures the recovery of these costs, which is consistent with the TRM and general ratemaking principles.

Decision

BPA adopts the Load Growth Rate Customer Charge to recover the financial shortfall from customers that elected the Tier 2 Load Growth service and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate.

2.5.4 Transmission Scheduling Service (TSS) Cap

Issue 2.5.4.1

Whether BPA should remove the monthly TSS price cap for unspecified resource amounts.

Parties' Positions

JP02 argues that BPA should not completely remove the monthly TSS price cap for unspecified resource amounts. JP02 Br., BP-16-B-JP02-01, at 5; *see also* Stratman *et al.*, BP-16-E-JP02-02, at 13. JP02 recommends that instead BPA should apply a modified monthly cap to TSS for

unspecified resource amounts based on an assumption of three scheduling transactions per day. JP02 Br., BP-16-B-JP02-01, at 5, 9.

BPA Staff's Position

In the Initial Proposal, Staff proposed to continue to apply the TSS price cap to customers with specified resources but to remove the price cap entirely for customers with unspecified resource amounts. Stiffler *et al.*, BP-16-E-BPA-17, at 9. In rebuttal testimony, Staff identifies an alternative, which would set the TSS price cap for unspecified resource amounts based on an assumption of three schedules per day. Weekley *et al.*, BP-16-E-BPA-35, at 31.

Evaluation of Positions

TSS is a service provided by BPA's Power Services to undertake certain scheduling operations on behalf of the customer. Stiffler *et al.*, BP-16-E-BPA-17, at 9. The current BP-14 TSS charge is subject to a cap such that if the annual cost to the customer using the TSS rate exceeds \$990/month, then the monthly charge is capped at \$990/month. *Id.*; GRSP II.U.4. The current price cap applies to specified resources and unspecified resource amounts. A "specified resource" as defined in the CHWM contract refers to a generating resource or contract resource the customer must use to serve its Total Retail Load. An "unspecified resource amount," also as defined in the CHWM contract, is an amount of energy the customer must use to serve its Total Retail Load and is not attributed to a specified resource.

In the Initial Proposal, Staff proposed to limit application of the TSS price cap to customers with specified resources. *Id.* The current price cap was calculated based on a cost to BPA per transaction. *Id.* However, customers with unspecified resource amounts can use, and are using, multiple scheduling transactions to meet the single unspecified resource contractual obligation. *Id.* When Staff originally designed the TSS rate, it assumed that a single contractual obligation was equal to a single transaction. *Id.* at 10. This assumption is true for specified resources but is not necessarily true for unspecified resource amounts. *Id.* The intent of the cost cap is to reflect the assumption that BPA's costs do not increase with the size of a transaction. *Id.*

JP02 disagrees with entirely uncapping monthly TSS charges for unspecified resource amounts for two reasons. JP02 Br., BP-16-B-JP02-01, at 7. First, JP02 argues, BPA has not clearly demonstrated the extent of the additional burden that additional scheduling transactions are placing on Staff. *Id.* Second, JP02 asserts, by attempting to address a cost shift that might be borne by specified resources, BPA's proposal to entirely uncap TSS charges for unspecified resource amounts would in turn create an unfair cost shift to those unspecified resource amounts. *Id.* In rebuttal testimony, Staff notes that there is some merit to JP02's proposal that unspecified resource amounts should be subject to a higher TSS price cap rather than the price cap being removed entirely. Weekley *et al.*, BP-16-E-BPA-35, at 30. This is true particularly if customers with unspecified resource amounts are willing to limit their daily scheduling transactions to a specific number instead of being completely unbound, as they are currently. *Id.* However, Staff supports waiting until the BP-18 rate case to explore whether customers are willing to place a cap on daily scheduling transactions. *Id.* In the meantime, for BP-16, Staff states that it would support either of the two alternatives. *Id.* at 31. Staff also suggests that both alternatives should

be reevaluated if customers are willing to commit in the next rate case (BP-18) to schedule no more than a pre-established number of daily transactions. *Id.*

JP02 urges the Administrator to adopt the second of the two alternatives proposed by Staff for BP-16, whereby an assumption of three schedules per day would be used to set the TSS price cap for unspecified resource amounts. JP02 Br., BP-16-B-JP02-01, at 9. JP02 states that BPA has not offered evidence that any unspecified resource amount has used more than three scheduling transactions per day to date, yet many have used fewer than three transactions per day. JP02 Br., BP-16-B-JP02-01, at 9. JP02 argues that, given that information, this is a conservative cap and one that will still result in some unspecified resource amounts paying a significantly higher charge for TSS than an equivalently sized specified resource would, even when they both use only one scheduling transaction. *Id.*

Decision

BPA will not remove the TSS cost cap for unspecified resource amounts but will change the existing cap to be based on an assumption of three scheduling transactions per day.

This page intentionally left blank.

3.0 GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICE RATE SCHEDULE

The purpose of the generation inputs portion of the rate proceeding is to assign certain power costs from Power Services to Transmission Services. Many products and services that Transmission Services provides to its customers require generation to supply capacity or energy. This generation is referred to as generation inputs, and these inputs are necessary for most of the ancillary and control area services that Transmission Services provides under its Open Access Transmission Tariff.

BPA Staff proposes FY 2016–2017 rates for the ancillary and control area services of the BP-16 rate case that reflect the terms of the Partial Settlement Agreement between BPA and the rate case parties. Fisher and Fredrickson, BP-16-E-BPA-12. As noted in ROD section 1.1.1.3, no rate case party objected to the Partial Settlement Agreement. The ACS-16 rates for Regulation and Frequency Response, Variable Energy Resource Balancing Service, Dispatchable Energy Resource Balancing Service, Operating Reserve – Spinning, Operating Reserve – Supplemental, Energy Imbalance, and Generation Imbalance are specified in Attachment 2 to the Partial Settlement Agreement. The Partial Settlement Agreement appears as Appendix A to this ROD; *see* pages A-16 through A-56.

Attachment 3 to the Partial Settlement Agreement, Inter-Business Line Allocations, includes the cost allocation for generation inputs for other products and for inter-business line costs. *Id.* at A-57. In addition to the generation inputs needed to provide ancillary and control area services described above, generation inputs also refers to certain cost assignments for specific services that Transmission Services either requires to maintain system reliability or offers to its customers. These generation inputs include Synchronous Condensing, Generation Dropping, Redispatch, and Station Service. *Id.* The inter-business line assignment of costs also includes the segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities. *Id.* These segmented costs are not generation inputs but instead are costs in the Power Services' revenue requirement that are assigned to Transmission Services to be recovered through transmission rates.

The Partial Settlement Agreement is the product of a regional consensus, and the rates established in the Partial Settlement Agreement meet BPA's statutory ratemaking standards discussed in ROD sections 1.1.2.1 and 1.1.2.2. The rates and cost allocations proposed in the Partial Settlement Agreement are hereby adopted.

This page intentionally left blank.

4.0 TRANSMISSION TOPICS

4.1 Segmentation

Segmentation is the process under which BPA assigns its transmission facilities to “segments” based on the types of services those facilities provide and then assigns to each segment the investment and historical operations and maintenance (O&M) expenses associated with the facilities in that segment. Tenney *et al.*, BP-16-E-BPA-16, at 2. The aggregate investment and historical O&M assigned to each segment are used in the Revenue Requirement Study to develop each segment’s revenue requirement, which is then used in the Transmission Rates Study to calculate rates. *Id.*

BPA Staff proposes to maintain the same seven segments as in BP-14: Generation Integration, Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. *Id.* at 25. In its Initial Proposal, Staff proposed three changes to the segment definitions:

- (1) Revising the definitions of the Network and Utility Delivery segments to distinguish facilities by function instead of by a 34.5-kV voltage threshold
- (2) Removing the term “integration” from the definition of the Network segment
- (3) Revising the definition of the Generation Integration segment to restore comparable treatment of equipment interconnecting Federal and non-Federal generators

Id. As discussed further below, in rebuttal testimony Staff maintained the new segment definitions but applied a functional test for distinguishing between Network and Utility Delivery to specific equipment within substations providing delivery service. Fredrickson *et al.*, BP-16-E-BPA-27, at 2-9, 13.

Staff also proposed three changes to the segmentation analysis to better align investment and historical O&M with the different segments:

- (1) Basing annual O&M expenses on the average expenses of the last seven years instead of three
- (2) Allocating historical vegetation management and right-of-way O&M expenses to the segments based on the percentage of transmission line O&M assigned to those segments, instead of the percentage of O&M related to lines, stations, and meters
- (3) Allocating station investment in facilities used for delivering Grand Coulee reserved power to all segments based on the share of direct station investment in each segment, instead of allocating this investment solely to the Utility Delivery segment

Tenney *et al.*, BP 16-E-BPA-16, at 25. Except for Staff’s revised application of the functional test, no party challenged or raised an issue regarding the changes. Therefore, the new definitions and the changes to the segmentation analysis are adopted.

Assignment of Facilities to the Network and Delivery Segments

The segmentation of facilities between the Network and Utility Delivery segments has been a controversial issue ever since BPA unbundled its power and transmission rates in 1996. *See* 1996 Wholesale Power and Transmission Rate Proposal, Administrator’s Final Record of Decision, WP-96-A-02, at 413-15 (July 1996). The controversy was abated though not fully resolved by settlements in 1996 and subsequent rate cases (until the BP-14 rate case, which was BPA’s first fully litigated transmission case in over two decades). In the 1996 settlement, most parties accepted, and the Administrator adopted, a 34.5-kV voltage threshold to distinguish between the Network segment and the DSI and Utility Delivery segments. Based on that threshold, facilities at 34.5 kV and above were assigned to the Network, and facilities below 34.5 kV were assigned to the appropriate delivery segment.

In the BP-14 rate case, the Administrator adopted Staff’s proposal to maintain the 34.5-kV voltage threshold. However, the Administrator took notice of the issues raised by a number of parties and committed Staff to engage with the region after the rate case to review BPA’s segmentation methodology. *See* BP-14 Power and Transmission Rate Proceeding, Administrator’s Final Record of Decision, BP-14-A-03, at 81-85 (July 2013) (BP-14 ROD).

The resulting regional review focused primarily on the assignment of facilities to the Network and Utility Delivery segments. Tenney *et al.*, BP-16-E-BPA-16, at 10-16. Participants proposed a wide range of alternatives, including the status quo. At the conclusion of the review, Staff prepared a white paper describing the alternatives and impacts of each alternative on BPA’s rates and customers. *See id.* at Attachment 2. BPA Staff used the review to develop its BP-16 Initial Proposal. *Id.* at Attachment 2, at A2-4.

In the Initial Proposal, Staff proposed to replace the 34.5-kV voltage threshold with a functional test under which facilities are assigned to the appropriate delivery segment if delivery of power is made at the customer’s prevailing distribution voltage and to the Network segment if delivery is made above the customer’s prevailing distribution voltage. Tenney *et al.*, BP-16-E-BPA-16, at 26-30. Recognizing the longstanding agreements and understandings between BPA and its customers regarding the construction of existing utility delivery facilities, Staff also proposed to grandfather into the Network and Utility Delivery segments all existing facilities in those segments. *Id.* at 31.

BPA’s small public customers strongly opposed Staff’s Initial Proposal, claiming that it left the Utility Delivery rate at an unsustainable level. Saven *et al.*, BP-16-E-NR-01, at 3-4; Scott, BP-16-E-PN-01, at 1; Saleba *et al.*, BP-16-E-WG-01, at 39-40. Over the past 20 years, BPA has sold many of its low-voltage delivery substations to its customers. Because of these sales, “the Utility Delivery segment is a shadow of its former self.” Saven *et al.*, BP-16-E-NR-01, at 9. Many remaining substations pose financial or operational issues that impede utilities from acquiring them. *Id.* at 9-10. They are often the more expensive substations on a per-megawatt

basis. Fredrickson *et al.*, BP-16-E-BPA-27, at 7. This not only makes them more difficult to sell but, as the less-expensive substations have been sold, increases the average cost of the remaining substations and thus the Utility Delivery rate. *Id.* Therefore, as the number of delivery facilities has declined, the pressure on the Utility Delivery rate has grown; under Staff's Initial Proposal, BPA would have to increase the rate by 147 percent to achieve full cost recovery. Frederickson *et al.*, BP-16-E-BPA-14, at 13, Fredrickson *et al.*; BP-16-E-BPA-14-E01, at 1; *see also* Saven *et al.*, BP-16-E-NR-01, at 10.

Only 33 utilities still take Utility Delivery service, and they are among BPA's smallest and most rural customers. Saleba *et al.*, BP-16-E-WG-01, at 38. Fifty-two percent of these utilities have an annual load of less than 10 aMW, and 64 percent have fewer than 5,000 retail customers. *Id.* These utilities are the least able to bear significant rate increases. Furthermore, for 12 of these customers, the only point of delivery on BPA's transmission system is a Utility Delivery facility. *Id.* Those utilities pay both the Utility Delivery charge and a Network transmission rate for all of their power deliveries on BPA's transmission system. *Id.*

In its rebuttal testimony, Staff refined its functional test by applying it to the equipment within a substation rather than to the substation as a whole. Staff determined that the equipment on the high side of the transformers (such as switches and circuit breakers installed to isolate the delivery equipment from the network) and all station general (station general includes roads, fences, buildings, and other basic infrastructure) serve a Network function. Therefore, Staff assigned this equipment to the Network. Staff assigned the delivery transformer and low-side equipment to the delivery segments. Fredrickson *et al.*, BP-16-E-BPA-27, at 2-9.

No parties oppose the new segment definitions or Staff's proposal to apply a functional test to new facilities and to grandfather existing Network facilities. However, Staff's proposal to assign the high-side equipment and all station general in facilities that provide delivery service to the Network segment received both support and opposition.

Issue 4.1.1

Whether equipment on the high side of delivery transformers and station general in facilities that provide delivery service should be assigned to the Network segment.

Parties' Positions

Iberdrola, JP04, JP12, JP14, and Powerex oppose Staff's revised proposal. Iberdrola argues that Staff's revised proposal to assign the high-side equipment and station general to the Network segment is a reversal of BPA's prior positions and contrary to BPA's own segmentation studies. Iberdrola Br., BP-16-B-IR-01, at 17. Iberdrola asserts that Staff has not provided adequate reasoning to depart from the functional test proposed in the Initial Proposal. *Id.* at 18. Iberdrola urges the Administrator to reject Staff's revised proposal and end the "improper subsidization" of the Utility Delivery segment by Network customers. *Id.* at 15, 19.

JP04 argues that the record contains no evidence that BPA’s segmentation methodology would encourage the widest possible diversified use of electric power in the Pacific Northwest at the lowest possible rates consistent with sound business principles. JP04 Br. Ex., BP-16-R-JP04-01, at 6.

JP12 argues that Staff’s revised proposal violates cost-causation principles because delivery substations were built to provide delivery service. JP12 Br., BP-16-B-JP12-02, at 3. JP12 argues that Network customers should not be assigned the costs of facilities that provide “low-voltage deliveries” since they were built for some customers and not others. *Id.* at 4. JP12 concludes that Staff’s revised proposal violates section 7(a)(2)(C) of the Northwest Power Act, which requires BPA to equitably allocate transmission costs between Federal and non-Federal power using the transmission system. *Id.* at 5.

JP14 argues that Staff’s revised proposal is inconsistent with the Administrator’s decision in the BP-14 rate case to gradually increase the Utility Delivery rate to full cost recovery. JP14 Br., BP-16-B-JP14-01, at 2-3. JP14 contends that there have been no changes since BP-14 to justify a change to the existing Utility Delivery segment. *Id.* at 4-5. JP14 also asserts that Staff’s revised proposal inappropriately bases segmentation on rate design rather than technical criteria and that it violates general cost-causation principles because it assigns facilities to the Network segment that were built to support the delivery of power to particular customers. *Id.* at 5-8. Finally, JP14 argues that grandfathering existing facilities into the Network segment while reassigning certain delivery facilities to the Network segment based on function is arbitrary and contrary to sound business principles. *Id.* at 8-9.

Powerex argues that Staff’s revised proposal is an “outcome-determinative, rate-driven exercise” intended to ameliorate a substantial rate increase to Utility Delivery customers. Powerex Br., BP-16-B-PX-01, at 28. Powerex contends that Staff’s revised proposal undermines the regional review process held prior to the BP-16 rate case. *Id.* at 26-27.

NRU, PNGC, and WPAG support Staff’s revised proposal. NRU and PNGC argue that the revised proposal comports more closely with cost causation because it creates a more refined demarcation between the Network and delivery segments. NRU Br., BP-16-B-NR-01, at 3-4; PNGC Br., BP-16-B-PN-01, at 2-5. NRU and PNGC also argue that Staff’s revised proposal provides a sustainable solution to a longstanding, contentious issue. NRU Br., BP-16-B-NR-01, at 8; PNGC Br., BP-16-B-PN-01, at 5.

PNGC and WPAG argue that Staff’s revised proposal encourages the widest possible diversified use of electric energy. PNGC Br., BP-16-B-PN-01, at 5; WPAG Br., BP-16-B-WG-01, at 7-8. WPAG further argues that the revised proposal creates a better balance between encouraging the widest possible diversified use and cost-causation because it balances the economic impact to BPA’s smallest customers—those that pay the Utility Delivery charge—and the costs of the equipment necessary to provide delivery service. *Id.* at 11-12; WPAG Br. Ex., BP-16-R-WG-01, at 2. WPAG also supports BPA’s proposal to grandfather existing Network facilities into the Network. *Id.*

BPA Staff's Position

BPA Staff states that its revised proposal creates a long-term, sustainable solution to the Utility Delivery rate. Fredrickson *et al.*, BP-16-E-BPA-27, at 12. Under Staff's revised proposal, the rate fully recovers the costs of the Utility Delivery segment. *Id.* at 19. Moreover, this proposal balances cost causation with BPA's statutory directive to encourage the widest possible diversified use at the lowest possible rates consistent with sound business principles while not imposing an undue economic burden on Utility Delivery customers. *Id.* at 12.

Staff states that the assignment of high-side equipment to the Network is appropriate because these facilities perform a Network function. *Id.* at 8. In addition, Staff's Initial Proposal assigned high-side equipment to the Utility Delivery segment if it was located in a facility segmented entirely to Utility Delivery and to the Network if it was located in either a multi-segmented facility or a Network-only facility, even if the equipment performed the same function. *Id.* at 10-12. Staff's revised proposal segments the high-side equipment the same way regardless of the location of the equipment. *Id.*

Staff states that station general should be included in the Network segment because the substation exists to deliver power to customers over BPA's Network, whether the substation includes transformation to delivery voltage or not. *Id.* at 8-9. BPA would have built the substation and incurred station general costs regardless of the voltage at which BPA delivers the power. *See id.*

Evaluation of Positions

In the Initial Proposal, BPA Staff proposed a segmentation methodology that would have resulted in a 25 percent increase to the Utility Delivery rate. Fredrickson *et al.*, BP-16-E-BPA-27, at 6. That increase would have followed a 25 percent rate increase in the BP-14 rate case. WPAG Br., BP-16-B-WG-01, at 10. Under the Initial Proposal, the BP-16 rate would have been \$1.749/kW/mo., which is almost the same as the NT rate for Network service (\$1.753/kW/mo.). Scott, BP-16-E-PN-01, at 3. This result seemed unreasonable because delivery service is the final and shortest portion of the customer's total transmission path, usually only a few feet, and is the last in a series of transformations. Fredrickson *et al.*, BP-16-E-BPA-27, at 6. A customer taking Utility Delivery service in addition to Network service would have paid \$3.502/kW/mo. (\$1.749 + \$1.753) under the Initial Proposal, while a customer taking only Network service would pay \$1.753/kW/mo. Staff expected the Utility Delivery rate to exceed the NT rate after the next rate case. *Id.*

Staff's Initial Proposal would likely cause Utility Delivery customers significant economic harm. Scott, BP-16-E-PN-01, at 1, 4-5; Saleba *et al.*, BP-16-E-WG-01, at 39-40. For example, the Town of Steilacoom is one of BPA's smallest customers, with an annual load of 4.9 aMW. Saleba *et al.*, BP-16-E-WG-01, at 39-40. Steilacoom has a single point of delivery on BPA's transmission system, the Steilacoom substation, a 12.5 kV Utility Delivery facility. *Id.* Under the Initial Proposal, the Utility Delivery charge would have been 40 percent of Steilacoom's total transmission bill. *Id.* Under the Initial Proposal segmentation, a Utility Delivery rate that fully recovered costs would increase the Utility Delivery charge for Steilacoom to 56 percent of its

total transmission bill. *Id.* at 40. The cost of Utility Delivery service would represent almost eight percent of Steilacoom’s total annual utility budget ($\$269,336 \div \$3,402,884 = 0.079$). *Id.* at 41. Steilacoom is not unique. As noted above, the customers that remain subject to the Utility Delivery charge lack the size and diversity of larger utilities and therefore are generally least able to absorb the impact of continued rate increases. *Id.* at 42.

Upon re-evaluation, Staff agreed that its Initial Proposal would have placed too great a financial burden on Utility Delivery customers. Fredrickson *et al.*, BP-16-E-BPA-27, at 6-7. Increasing the rate by 25 percent per rate period over successive rate periods would have caused significant rate shock, especially because until 1996 BPA recovered the costs of the delivery facilities in rates for the sale of delivered power. Before 1996 BPA had no separate utility delivery rate, and between 1996 and 2014 a series of transmission rate settlements established a Utility Delivery rate that did not fully recover costs. Fredrickson *et al.*, BP-16-E-BPA-27, at 4; *see also* Scott, BP-16-E-PN-01, at 4. It was only in the BP-14 rate case that BPA began the transition to full cost recovery by the Utility Delivery rate, leading to the prospect of large rate increases over successive rate periods. Fredrickson *et al.*, BP-16-E-BPA-27, at 4.

Thus, considering the economic impact of the rate on customers is consistent with BPA’s historical treatment of Utility Delivery facilities. Moreover, BPA is statutorily required to set rates that encourage the widest possible diversified use of electric power in the Pacific Northwest at the lowest possible rates consistent with sound business principles. *See, e.g.*, 16 U.S.C. §§ 832a(b), 832e, 825s, 838g. By making delivery service costs unduly burdensome, these significant rate increases would run counter to this directive. Fredrickson *et al.*, BP-16-E-BPA-27, at 6-7; Scott, BP-16-E-PN-01, at 5; Saleba *et al.*, BP-16-E-WG-01, at 42-43. As Senator McNary stated regarding the inclusion of the directive in the Bonneville Project Act:

That is not in the Boulder Canyon Act, it is not in the Muscle Shoals Act. It is sought by their provision to make certain that any benefits which may accrue shall not be provincial in their application but shall be distributed as far as is practicable, a matter which can only be worked out through experience and study. But we have placed no limitations on the area of distribution. *The language encourages a wide and equitable distribution of the benefits of the rates which may be enjoyed by the people who live in the great Northwest section of the country.*

75 Cong. Rec. S8523 (daily ed. Aug. 9, 1937) (remarks of Sen. McNary) (emphasis added).

JP04 argues that the record contains no evidence that BPA’s proposed segmentation would encourage the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. JP04 Br. Ex., BP-16-R-JP04-01, at 6. In fact, however, the evidence demonstrates that the segmentation in Staff’s Initial Proposal, combined with expected future rate increases, would place a great burden on many small utilities that take Utility Delivery service. Scott, BP-16-E-PN-01, at 1, 4-5; Saleba *et al.*, BP-16-E-WG 01, at 39-42. It is not necessary to wait until one or two utilities cut back their service because of higher rates before adopting a different segmentation methodology. The far better policy is to

adopt a segmentation methodology now that avoids this outcome, while recognizing that customers taking delivery service receive an additional benefit that they should pay for.

JP14 argues, however, that Staff is attempting to resolve “a rate design issue” through segmentation, which JP14 says should be based on engineering and technical analysis. JP14 Br., BP-16-B-JP14-01, at 5-6. To the contrary: segmentation involves both rate design and engineering and technical analysis. Segmentation fundamentally concerns the allocation of costs among customers, which is part of rate design. This allocation should be based on BPA’s various statutory directives and policies, and should be structured to achieve the best possible balance among them.

Iberdrola and Powerex argue that Staff’s revised proposal is an outcome-determinative, rate-driven exercise intended to ameliorate a substantial rate increase to Utility Delivery customers. Iberdrola Br., BP-16-B-IR-01, at 18; Powerex Br., BP-16-B-PX-01, at 27-28. Staff acknowledges that it re-evaluated its Initial Proposal because of the issues raised by PNGC and WPAG regarding the level of the Utility Delivery charge. Fredrickson *et al.*, BP-16-E-BPA-27, at 6. Iberdrola and Powerex’s mistake is in thinking that the effort to render the rate more affordable is inappropriate. To the contrary, it would be inappropriate for BPA to ignore the effect of rate increases on its customers.

Powerex contends that Staff’s revised proposal undermines the regional review process held prior to the BP-16 rate case because Staff proposed a different segmentation in rebuttal testimony. Powerex Br., BP-16-B-PX-01, at 26-27. The purpose of the regional review process was to engage the region in a discussion regarding segmentation that would inform Staff’s Initial Proposal; decisions regarding segmentation must be made in a rate case. Powerex is essentially arguing that, once Staff decided on a proposal, it should have disregarded the parties’ testimony. That course would make a nullity of the rate case. Although Powerex argues that Staff “disregards customer input,” *id.* at 27, the opposite is true. By responding to the parties’ cases Staff showed that it values customer input highly.

The distinction between Staff’s initial and revised proposals concerns the high-voltage equipment and station general at substations where BPA provides delivery transformation (transformation to distribution-level voltages). Fredrickson *et al.*, BP-16-E-BPA-27, at 5, 8. Under Staff’s Initial Proposal, the Utility Delivery segment included the high-voltage equipment associated with the delivery transformation and a pro rata share of station general investment, which was based on the investment in major equipment, such as transformers, circuit breakers, and disconnect switches at the substation. *Id.* at 2-3. Under Staff’s revised proposal, the high-side equipment and all of station general are assigned to the Network segment, just as they are in all other substations that provide service to Network customers. *Id.* at 7-8.

JP14 asserts that Staff presented no evidence that the substations or associated equipment have changed from an engineering or technical standpoint. JP14 Br., BP-16-B-JP14-01, at 7-8. JP14 again incorrectly assumes that segmentation must be based entirely on engineering and technical criteria. *Id.* at 5-6. Moreover, Staff’s revised proposal does hinge largely on technical criteria. Staff included the high-side equipment in the Network because that equipment exists to separate

BPA's Network from the customer's system for operational, maintenance, and reliability purposes and as such serves a Network function. Fredrickson *et al.*, BP-16-E-BPA-27, at 7-8. The high-side equipment is necessary to protect the Network from faults in the delivery transformer or low-voltage equipment. Only the delivery transformer and the low-side equipment perform a delivery function. This equipment remains assigned to the Utility Delivery segment. *Id.* at 8. NRU, PNGC, and WPAG agree with Staff's analysis. NRU Br., BP-16-B-NR-01, at 4-7; PNGC Br., BP-16-B-PN-01, at 2-4; WPAG Br., BP-16-B-WG-01, at 11-12.

The difference between Staff's Initial Proposal and its revised proposal is that Staff performed a more refined analysis of the substations. Instead of using a gross analysis that assigned an entire substation to one or the other segment, Staff analyzed the actual equipment in the substation to determine the function it performs. Fredrickson *et al.*, BP-16-E-BPA-27, at 8. As NRU, PNGC, and WPAG assert, the revised proposal adheres even more closely to cost causation principles because it provides a more granular demarcation between the Network and delivery segments. NRU Br., BP-16-B-NR-01, at 4-7; PNGC Br., BP-16-B-PN-01, at 2-4; WPAG Br., BP-16-B-WG-01, at 12-13.

Moreover, BPA's existing segmentation assigns some high-side equipment to different segments depending on whether the equipment is in a delivery substation or in a substation that also includes Network equipment. Staff's Initial Proposal continued this treatment. Fredrickson *et al.*, BP-16-E-BPA-27, at 10-12. Staff's revised proposal, however, consistently assigns equipment to segments based on function. For example, in its rebuttal testimony Staff compares the segmentation of equipment in the Reedsport, Gardiner, and Tahkenitch substations. *Id.* at 11-12 & Att. 2. At both the Reedsport and Gardiner substations BPA delivers power at the customer's distribution voltage. *Id.* at 11-12. The high-side equipment that isolates the delivery transformer at the Reedsport substation is in the Reedsport substation. Under the existing segmentation this equipment is assigned to the Utility Delivery segment.

The high-side equipment that isolates the delivery transformer at Gardiner is located a short distance away from Gardiner at the Tahkenitch substation. *Id.* Under the existing segmentation this equipment is assigned to the Network segment. Yet in both cases the high-side equipment performs the same function—protecting the network from faults in the delivery transformer or low-side equipment. The only difference, which is irrelevant from a technical standpoint, is the location of the equipment. Under BPA's existing segmentation the equipment is treated inconsistently because Staff viewed the substation as a whole instead of considering the function of the equipment within it. Under Staff's more refined approach, the high-side equipment at both the Reedsport and Tahkenitch substations is assigned to the Network segment.

Staff assigned all station general to the Network segment because the substation where the delivery transformation occurs is a Network facility. The Network extends to where the delivery transformation occurs; the substation is the terminus of the network line. Fredrickson *et al.*, BP-16-E-BPA-27, at 8-9. Some substations transform power down to a level—say, 69 kV—that is still a Network-level voltage. These substations are assigned entirely to the Network segment. Other substations transform power down to a distribution voltage—say, 12.5 kV. Under BPA's

existing segmentation, station general in these substations is assigned in part to the Network segment and in part to the Utility Delivery segment.

Yet the two substations are identical except for the voltage on the low side of the transformer. *Id.* Both exist to deliver power over BPA’s Network to the customer; the voltage on the low side of the transformer does not change the function of the remainder of the substation. *Id.* BPA would incur similar station general costs regardless, and they should not be assigned to Utility Delivery customers simply because those customers take an additional service that does not cause BPA to incur additional station general costs.

JP14 argues that Staff’s revised proposal regarding high-side equipment is inconsistent with Staff’s own proposed definition of the Network segment. The Network segment includes facilities that provide certain reliability and other benefits to BPA and its customers. JP14 Br., BP-16-B-JP14-01, at 6. As stated above, the high-side equipment benefits the Network segment because it allows BPA to isolate the Network from the delivery transformer and the customer’s system for operational, maintenance, and reliability purposes. This equipment provides benefits to the Network just as similar equipment does in substations at which higher-voltage delivery occurs.

Iberdrola argues that the revised proposal is a reversal of BPA’s prior positions and contrary to BPA’s own segmentation studies. Iberdrola Br., BP-16-B-IR-01, at 17. It is true that prior segmentation studies assigned certain high-side equipment and station general to the delivery segments. However, as explained above, that assignment was inconsistent with the segmentation of other high-side equipment and station general in the Network segment performing the identical function at other locations. Staff’s revised proposal treats this equipment and station general consistently across BPA’s system.

JP12 contends that it is inequitable to require network customers to pay for a portion of the cost of substations that were installed to provide lower-voltage deliveries to a subset of BPA’s customers. JP12 Br., BP-16-B-JP12-02, at 4. JP12 incorrectly assumes that these substations exist only because they include a low-voltage transformer. As discussed above, if BPA had not installed a low-voltage transformer, it still would have built the substation, which would deliver power to the customer at a transmission voltage.

It is true that under BPA’s former customer service policies BPA built low-voltage facilities for some customers but not for others. BP-14 ROD at 99. As discussed above, however, the high-side equipment and station general serve a Network function, and therefore it is appropriate to assign them to the Network segment.

JP12’s argument highlights the fundamental flaw in the opposition to Staff’s revised proposal. Under the Bonneville Project Act, the Administrator is authorized to adopt rate schedules that “provide for uniform rates or rates uniform throughout prescribed transmission areas in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville project.” 16 U.S.C. § 832e. The Transmission

System Act likewise authorizes the Administrator to establish “uniform rates or rates uniform throughout prescribed transmission areas.” *Id.* § 838h.

If it is permissible to roll all facilities into one segment and charge a single rate for all transmission service without regard to cost causation, surely it is permissible to establish segments based on rational criteria grounded not only in cost causation but in BPA’s enabling statutes taken as a whole. That is particularly true in a case such as this, in which a segmentation policy is being adopted in part to fulfill the policy of the uniform rates statute itself.

JP12 argues, however, that Staff’s revised proposal violates the equitable allocation standard, under which BPA must equitably allocate the costs of the transmission system between Federal and non-Federal power utilizing the system. JP12 Br., BP-16-B-JP12-02, at 5, *citing* 16 U.S.C. § 839e(a)(2)(C).

JP12 offers no evidence that Staff’s revised proposal assigns costs differently for Federal and non-Federal uses. Under Staff’s proposal, costs are not allocated separately for Federal and non-Federal uses, and all customers pay the same rate. Tenney *et al.*, BP-16-E-BPA-16, at 33-34; *see also* WPAG Br., BP-16-B-WG-01, at 6-7. Thus, the proposal does not advantage either Federal or non-Federal power. If Federal use is greater, Federal use will recover more of the costs of the transmission system; if Federal use is less, it will recover less. The same holds for non-Federal use.

JP14 argues that Staff’s revised proposal is inequitable because it grandfathers existing facilities into the Network segment regardless of whether they would be considered Network facilities today, but transfers some existing facilities from the Utility Delivery segment to the Network if they are no longer considered Utility Delivery facilities. JP14 Br., BP-16-B-JP14-01, at 8-9. These two cases are fundamentally different. Unlike the Network segment, in which facilities are socialized over a broad base of customers, the Utility Delivery segment is socialized over a small subset of customers that also pay the Network rate. The effect of grandfathering the Network facilities is far less than the effect of grandfathering Utility Delivery facilities would be. Tenney *et al.*, BP-16-E-BPA-16, at 32. BPA can satisfy all of its rate objectives despite the grandfathering of certain Network facilities; if BPA grandfathered Utility Delivery facilities, on the other hand, it could seriously burden its existing Utility Delivery customers.

Decision

Equipment on the high side of delivery transformers and station general in facilities that provide delivery service will be assigned to the Network segment.

Issue 4.1.2

Whether operations and maintenance (O&M) costs of facilities that are transferred to the Network should be allocated to the Utility Delivery segment.

Parties' Positions

JP14 argues that Network customers should not bear the O&M costs of any existing Utility Delivery facilities the Administrator assigns to the Network segment. JP14 Br., BP-16-B-JP14-01, at 9. According to JP14, allocating O&M costs to the Utility Delivery segment would provide an incentive for Utility Delivery customers to purchase delivery facilities and to replace facilities when the facilities are no longer cost-effective. *Id.*

BPA Staff's Position

Staff did not address this issue, but both its Initial Proposal and rebuttal proposal would assign O&M to segments pro rata based on investment. Transmission Segmentation Study and Documentation, BP-16-E-BPA-06, at 16-19.

Evaluation of Positions

JP14's argument that Utility Delivery customers should continue to bear O&M costs of reassigned facilities as an incentive to purchase them contradicts one of JP14's own arguments: that O&M costs should be based solely on technical and engineering criteria. JP14 Br., BP-16-B-JP14-01, at 6. Here, JP14 argues that BPA should explicitly adopt economic criteria as a basis for segmentation. *Id.* at 4-5. In this case, however, there is no reason to do so. JP12's argument is inconsistent with one of the fundamental tenets of segmentation and rate design—that O&M follows investment. This tenet makes sense because operations and maintenance of a facility performs the same function as the facility itself. BPA has never allocated O&M to segments on a basis different from the allocation of the investment.

In addition, Staff's revised proposal is based in part on technical criteria. Fredrickson *et al.*, BP-16-E-BPA-27, at 7-8. JP14 proposes an arbitrary assignment of O&M costs. The high-side equipment performs a network function and exists for the benefit of the network; the O&M for this equipment does so as well.

Decision

O&M costs of facilities that are transferred to the Network segment will be allocated to the Network segment.

Issue 4.1.3

Whether the cost of replacements for Utility Delivery facilities should be assigned to Utility Delivery customers.

Parties' Positions

JP14 argues that allocating replacement costs to Utility Delivery customers would put all customers on a level playing field and transition BPA away from providing delivery service. JP14 Br., BP-16-E-JP14-01, at 9.

Conversely, WPAG argues that the Administrator should clarify that even when a grandfathered facility is replaced with a facility with greater capacity to serve load growth, the facility should remain grandfathered. WPAG Br., BP-16-B-WG-01, at 10. WPAG contends that directly assigning the costs of replacement facilities needed for load growth would contradict BPA's Open Access Transmission Tariff and BPA's statutory obligation to encourage the widest possible diversified use of energy at the lowest possible rates consistent with sound business principles. *Id.* Moreover, a policy that directly assigned the costs of replacements to delivery customers would penalize them when BPA made past decisions regarding how it would serve those customers and the customers built their infrastructure accordingly. *Id.* at 9.

BPA Staff's Position

Staff proposes that segmentation of replacement facilities be determined on a case-by-case basis. Fredrickson *et al.*, BP-16-E-BPA-27, at 19. Replacement facilities that provide equivalent capacity would most likely be segmented in the same manner as existing facilities. *Id.* at 20. However, segmentation of replacement facilities that provide greater capacity than needed to serve a customer would likely depend on whether the higher-capacity facility was constructed for BPA's or the customer's convenience. *Id.*

Evaluation of Positions

The segmentation of replacement facilities need not be decided in this rate case. Staff is correct, however, that a number of considerations may govern this choice. Fredrickson *et al.*, BP-16-E-BPA-27, at 19-20. For now it suffices to say that this question will be decided on a case-by-case basis until a compelling reason is offered to establish a firm policy.

Decision

Decisions regarding the segmentation of replacement facilities will be made on a case-by-case basis.

4.2 Transmission Revenue Requirement and Risk Analysis

4.2.1 Transmission Revenue Requirement

The transmission and ancillary services rates being established in this case are designed to recover BPA's costs as set forth in the transmission revenue requirement. BPA determines generation (power) and transmission revenue requirements using separate repayment studies, consistent with the Commission's 1984 order. *See U. S. Dep't of Energy – Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984). Rates to recover the costs set forth in BPA's generation revenue requirement are being established in the power portion of the BP-16 case. The costs established in the power portion of the case also include inter-business line costs, or costs that one business line charges to the other. For example, Power Services charges Transmission Services for the costs of generation inputs used to provide ancillary services and for the annual costs of the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities that are included in the network and utility delivery segments. Transmission Services establishes ancillary and control area service rates to recover these costs and passes the revenues on to Power Services. BPA Staff proposes rates for the ancillary and control area services for the FY 2016–2017 rate period that reflect the terms of the Partial Settlement Agreement between BPA and the rate case parties. For additional information, see ROD Chapter 3, Generation Inputs and the Ancillary and Control Area Service Rate Schedule.

Consistent with BPA's statutory obligations, the transmission revenue requirement establishes the level of revenue required to recover all of BPA's costs of transmitting electric power, which include the Federal investment in transmission and transmission-supporting facilities; operations and maintenance expenses; transmission marketing and scheduling expenses; the cost of generation inputs for ancillary services and reliability; and all other transmission-related costs incurred by the Administrator. Transmission Revenue Requirement Study, BP-16-FS-BPA-08, § 1.1.

BPA develops its revenue requirement to recover its costs in conformance with its statutory obligations and the financial, accounting, and repayment requirements of the Department of Energy's Order RA 6120.2. *Id.*

As described in the study, BPA calculated its transmission revenue requirement for the FY 2016–2017 rate period using a cost accounting analysis consisting of three components:

1. Repayment studies are conducted for each year of the two-year rate period to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission. Repayment studies include a 35-year repayment period.
2. Operating expenses functionalized to transmission and minimum required net revenues (if needed) are projected for each year of the rate period (FY 2016–2017).
3. Annual planned net revenues for risk, if any, are determined based on the risks identified, BPA's cost recovery goals, and risk mitigation measures.

Based on these analyses, BPA sets the transmission revenue requirement at the revenue level necessary to fulfill BPA's cost recovery requirements. Department of Energy Order RA 6120.2 requires that BPA demonstrate the adequacy or inadequacy of its existing rates to recover its costs. BPA conducts a current revenue test to determine whether transmission revenues projected from current rates would meet cost recovery requirements for the rate test period and repayment periods. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, BPA can, on that basis, choose to extend current rates. The current revenue test shows that current rates would be insufficient to demonstrate cost recovery. *Id.*

After calculating proposed rates, BPA conducts a revised revenue test to determine whether projected revenues from proposed rates will meet cost recovery requirements for the rate test and repayment periods. BPA has proposed to increase the transmission rates to ensure cost recovery. The revised revenue test demonstrates that the rates proposed are sufficient to meet cost recovery requirements for the rate test and repayment periods. *Id.*

In the Initial Proposal, as in the previous five rate cases, BPA Staff proposed to use \$15 million of cash reserves attributed to Transmission Services (generally referred to below as reserves or financial reserves) in each year of the FY 2016–2017 rate period (a total of \$30 million in the two-year rate period) as a funding source for transmission capital programs, rather than using Treasury borrowing authority. This reserve financing assumption is included in the rate period revenue requirements. Lennox *et al.*, BP-16-E-BPA-13, at 10. The use of additional financial reserves attributed to Transmission to mitigate the proposed rate increase is discussed in Issue 4.2.2.1 below.

Issue 4.2.1.1

Whether BPA's forecast of net interest expense for transmission should be reduced by \$26.3 million per year to compensate for BPA's past forecasting errors.

Parties' Positions

JP07 argues that during the six-year period of 2009 to 2014, BPA over-forecast net interest expense for transmission by an average of \$34.4 million per year, and never less than \$28 million. JP07 Br., BP-16-B-JP07-01, at 8. JP07 states that although BPA has refined its revenue forecasting model and reduced under-forecasting of transmission revenue, the over-forecasting of interest expense has not declined. *Id.* JP08 recommends that to compensate for its persistent over-forecasting, BPA should reduce its forecast of net interest expense by 80 percent of the average error over the last six years, or \$26.3 million. *Id.* at 9. JP07 claims that since this amount is less than the smallest error in any year during that time period, it is a conservative adjustment. *Id.* JP07 claims that failure to adjust the forecast would perpetuate the errors, and sound business principles require that BPA consider past results in implementing its policies. *Id.*

BPA Staff's Position

Interest rate forecasts are based on the best available information at the time the forecasts are made, and a reduction of the forecast by \$26.3 million would be arbitrary. Lennox *et al.*, BP-16-

E-BPA-25, at 1, 4. Differences between forecasts and actual results exist because of a number of factors. For example, refinancing of debt, which BPA cannot always predict, accounted for a significant portion of the difference in 2011 and 2014. *Id.* at 2. In addition, the low-interest-rate environment that has persisted for a number of years has made forecasting difficult, as the long-expected increase in interest rates has yet to materialize. *Id.* at 3. BPA continues to refine its forecasting methodology and should continue to base the forecast on the best information available. *Id.* at 3-4.

Evaluation of Positions

JP07 notes correctly that in recent years BPA has tended to over-forecast net interest expense for transmission. However, Staff notes correctly that JP07's proposal for more accurate forecasts is arbitrary, and there is no reason to believe it will result in a more accurate forecast in this case. *Id.* at 4-5. JP07's only basis for reducing the forecast by 80 percent of the average error over the last six years is that it is "conservative." JP07 Br., BP-16-B-JP07-01, at 9. JP07 offers no reason to believe that the forecast will be off by that amount.

As with all other forecasts, the forecast of net interest expense should be based on the best information available at the time. Instead of reducing the forecast by an arbitrary percentage of past forecasting errors, BPA Staff has worked to refine its methodology to increase accuracy. Lennox *et al.*, BP-16-E-BPA-25, at 3-4. For example, Staff has refined its methodology for projecting the amount of debt it will issue during the rate period. *Id.* Staff projects borrowings with shorter maturities and lower interest rates, which reduces net interest expense. *Id.* at 4. In addition, the repayment model has been upgraded to more precisely calculate interest expense. Lennox *et al.*, BP-16-E-BPA-13, at 8.

JP07 argues that it is not businesslike to ignore the results of operations because they may be driven by individual events with unique causes. JP07 Br., BP-16-B-JP07-01, at 9. As shown above, Staff is not ignoring the results of operations. Instead, Staff continues to refine and improve its methodology and modeling tools to improve the accuracy of its forecasts. Lennox *et al.*, BP-16-E-BPA-25, at 3-4. If there is a systematic error in the forecast—and six years of data do not necessarily demonstrate as much—that is the appropriate response.

Decision

The forecast of net interest expense for transmission will not be reduced by \$26.3 million per year.

Issue 4.2.1.2

Whether the repayment study should be modified to eliminate critical years, change the due date of \$49 million of projected debt from FY 2027 to FY 2024, and increase use of the rollover feature.

Parties' Positions

JP04 argues that BPA's repayment study should be modified to minimize or eliminate the critical year identified in FY 2027 by changing the due date of \$49 million in projected debt from FY 2027 to FY 2024, which will reduce debt service included in transmission rates. JP04 Br., BP-16-B-JP04-02, at 14. JP04 also argues that the repayment study should be modified to reduce mandatory amortization in the critical year by paying some debt earlier as discretionary amortization whenever such action would reduce debt service. *Id.* In addition, JP04 argues, bond rollovers should be considered in the repayment model as a way to reduce debt service. *Id.* at 13. JP04 argues that BPA should describe how it used the rollover feature in the repayment model. JP04 Br. Ex., BP-16-R-JP04-02, at 2-3.

BPA Staff's Position

Changing the due dates of projected investments and the associated interest rates in the repayment study, which will affect the timing of principal payments by the repayment model, is a reasonable approach to reduce debt service. Lennox *et al.*, BP-16-E-BPA-25, at 7. At JP04's request, Staff performed two studies in which the due date of the \$49 million projected bond was changed, in one case to FY 2024. *Id.* at 6. In both studies debt costs were lower than in the Initial Proposal. *Id.* at 7. Staff committed to work toward reducing the repayment levels in the final rates but could not commit to adopting JP04's proposal because Staff did not yet know how the model would respond to the updates Staff would make for the final rates. *Id.*

Evaluation of Positions

A critical year in the repayment study is a year in which only debt that is due is paid. No discretionary amortization is paid that year. *Id.* at 6. Thus, the critical year sets the lowest possible level of debt service for the year being studied and the 35-year repayment period. *Id.*

JP04 notes correctly that 2027 is a critical year in the Initial Proposal repayment study. JP04 Br., BP-16-B-JP04-02, at 5. The two studies that Staff performed at JP04's request, Study 1 and Study 2, changed the due date and resulting interest rates for a single \$49 million bond that was projected to be issued in 2016 with an 11-year term. Lennox *et al.*, BP-16-E-BPA-25, at 6. Study 1 changed the term to 8 years. *Id.* Study 2 gave the bond its maximum possible term of 35 years, making it due in 2050. *Id.* at 7. Both studies produced lower levelized debt service than the Initial Proposal repayment study. *Id.*

Staff updated the repayment study for the final rates. The updates include new Federal and non-Federal debt issuances, refinancing of debt, repayment of principal since the Initial Proposal was issued, and a new interest rate forecast. After the updates, changing the terms of the \$49 million bond would not achieve the results obtained in the two earlier studies. Instead, Staff applied the

approach of the two studies to all of the projected investments by revising the due dates of all debt—either lengthening or shortening the term—and the resulting interest rates. Staff performed a number of studies and used the one that produced the lowest debt service. Staff lowered debt service from the Initial Proposal by an annual average of \$11.3 million in FY 2016–2017, a larger reduction than the one made by either Study 1 or Study 2.

As to bond rollovers, the repayment model does have a rollover feature. JP04 cited the extension of a particular bond’s due date in Study 2 as an example of the use of rollover to lower debt service. JP04 Br., BP-16-B-JP04-02, at 13. However, the change in the bond’s due date in Study 2 was not based on the rollover feature, which remained the same as in the Initial Proposal. Lennox *et al.*, BP-16-E-BPA-25, at 8-9. Therefore, JP04 has made no specific suggestion for changing the rollover feature or cited any instance in which different or additional use of the rollover feature would lower debt service. As noted, the repayment study includes a rollover feature that Staff has utilized.

JP04 also requested a description of how BPA used the rollover feature in the repayment model. JP04 Br. Ex., BP-16-R-JP04-02, at 2-3. In the final repayment study, Staff used the rollover feature on a number of historical bonds. Eight short-term bonds due in 2015 were rolled into 2031 and 2032. Seven bonds due in 2018-2019 were rolled into 2028 and 2029. For details of the bond rollovers see Transmission Revenue Requirement Study Documentation, BP-16-FS-BPA-08A, Table 12-8.

Decision

The repayment study will not be modified to eliminate critical years or to change the due date of the \$49 million bond from FY 2027 to FY 2024. Instead, the revised repayment study with a critical year of 2043 will be used for establishing rates. No changes will be made to the use of the rollover feature.

Issue 4.2.1.3

Whether the repayment of discretionary amortization should be scheduled based on the principle that debt with the highest interest rate is amortized first.

Parties’ Positions

JP04 argues that if a discretionary amortization schedule results in lower debt service than a schedule under which debt with the highest interest rate is amortized first, BPA should adopt the alternative discretionary amortization schedule. JP04 Br., BP-16-B-JP04-02, at 9. JP04 states that DOE Order RA 6120.2, which governs BPA’s repayment study, does not impose an absolute requirement that discretionary amortization always be scheduled by selecting the highest-interest-bearing investment first. *Id.* at 8. Instead, JP04 states, the DOE order allows for an exception to this principle when “otherwise indicated by legislation.” *Id.* JP04 claims that the Transmission System Act’s requirement that BPA set the lowest possible rates consistent with sound business principles is legislation that overrides the DOE order. *Id.* at 9, 17-18.

BPA Staff's Position

JP04 appears to misunderstand how Study 1 and Study 2 were performed. Both studies followed the highest-interest-rate-first principle of DOE Order RA 6120.2. *Lennox et al.*, BP-16-E-BPA-25, at 11. Therefore, the studies do not support JP04's argument that an alternative schedule would result in lower debt service. It is true that DOE Order RA 6120.2 allows for exceptions to the general rule. *Id.* at 10. Any alternative, however, must be consistent with sound business principles. Establishing the lowest possible rates is not always consistent with sound business principles. *Id.*

Evaluation of Positions

DOE Order RA 6120.2 provides that “to the extent possible ... and unless otherwise indicated by legislation,” revenues available for amortization shall be applied to the highest-interest-bearing investment first. JP04 Br., BP-16-B-JP04-02, at 8. Thus, the rule has two qualifications: the alternative amortization schedule must be possible, and legislation must indicate that BPA should follow an alternative schedule. JP04 has seized on the second qualification, arguing that BPA's statutory obligation to establish the lowest possible rates consistent with sound business principles means that it must use a different amortization schedule if it will result in lower rates. *Id.* at 17-18. JP04 challenges Staff's testimony that this statutory requirement is not the type of legislation Order RA 6120.2 was referring to. *Id.*

Although Staff stated its position inartfully, its testimony demonstrates that it was challenging the notion that BPA must always establish the lowest possible rates. As Staff noted, JP04 quotes the statute correctly but ignores its requirement that rates be consistent with sound business principles. *Lennox et al.*, BP-16-E-BPA-25, at 10. JP04 also argues that the repayment study should be modified to reduce mandatory amortization in the critical year “if such modification would reduce debt service included in BPA's transmission rates.” *Id.* at 14.

JP04 makes no argument that its alternative proposals are consistent with sound business principles. Moreover, JP04 did not contest Staff's testimony that Study 1 and Study 2—the evidence JP04 relies on—followed the highest-interest-rate-first principle. *Lennox et al.*, BP-16-E-BPA-25, at 11. As Staff testified, establishing the lowest possible rates is not always consistent with sound business principles, for example if lower rates today would mean significantly higher rates in the future and possible rate shock. *Id.*

JP04 argues that the Draft ROD mischaracterized its position by stating that JP04 assumed that lower rates were always consistent with sound business principles. JP04 Br. Ex., BP-16-R-JP04-02, at 3. It is true that JP04 correctly cited the statute, arguing that BPA must adopt the lowest possible rates consistent with sound business principles. However, JP04 did not identify any such principle or suggest that a lower rate would never be consistent with sound business principles. Although JP04 cited the statutory principle, it argued for the lowest possible rates.

In any case, JP04 has offered no evidence that an alternative amortization would result in lower rates. And as noted above, the updates to the repayment study lowered annual debt service by \$6 million, almost as much as JP04 requested.

Decision

Repayment study results will be based on the highest-interest-rate-first principle. No evidence has been offered to justify deviating from this rule.

Issue 4.2.1.4

Whether the repayment model should be made available to rate case parties.

Parties' Positions

JP04 argues that BPA's repayment model should be made available to rate case parties in executable form. JP04 Br., BP-16-B-JP04-02, at 20. JP04 Br. Ex., BP-16-R-JP04-02, at 5. JP04 claims that unless BPA makes the model available, parties will not have the opportunity required by the Northwest Power Act to offer refutation or rebuttal of any material submitted in the rate case and BPA's rates will not be supported by substantial evidence. *Id.*

BPA Staff's Position

The repayment model uses a proprietary system as its database with a Web-based interface in a multi-server environment. It cannot be installed off-the-shelf on a desktop computer. However, Staff is willing to explore ways to make the model accessible to the parties. Lennox *et al.*, BP-16-E-BPA-25, at 11-12.

Evaluation of Positions

The features of the model that Staff cites make it difficult to make the model available to the parties. *Id.* Staff did what it could in this rate case to ensure the parties' procedural rights. Staff ran the two studies the parties requested and made the results available. *Id.* at 6, 11-12. Staff was unable to go further and make the model available in executable form. However, BPA will explore whether it is possible to make the model more accessible to the parties, and if so, how to do so. BPA will discuss this issue with parties after the conclusion of this rate proceeding. JP04 argues that BPA must commit to more than just exploring what is possible and discussing it with customers. JP04 Br. Ex., BP-16-R-JP04-02, at 5. However, it is not prudent to commit to a particular course of action until it appears to be possible. Therefore, BPA cannot commit further at this time.

Decision

BPA will explore ways to make the repayment model available to rate case parties.

4.2.2 Transmission Risk Analysis

In the 1993 Final Record of Decision, BPA determined that, as a long-term policy, it would set its rates to maintain financial reserves sufficient to achieve at least a 95 percent probability of making its scheduled payments to the U.S. Treasury in full and on time for each two-year rate

period. 1993 Wholesale Power and Transmission Rate Proposal, Administrator’s Record of Decision, WP-93-A-02, at 72-73 (July 1993) (1993 ROD).

Because the Treasury payment is the last payment made in a fiscal year, the probability of making BPA’s year-end payments to the U.S. Treasury for each year of the rate period (TPP) is the primary measure of BPA’s ability to meet not only the Treasury obligation but all of its financial obligations within a fiscal year. BPA has applied the same risk analysis methods as it has in the past to measure the TPP for the FY 2016–2017 rate period. Lovell *et al.*, BP-16-E-BPA-15, at 2. Specific issues raised with respect to the revenue requirement and risk analysis are addressed below.

Issue 4.2.2.1

Whether financial reserves for risk attributed to Transmission Services should be used to mitigate the proposed transmission rate increase or fund transmission capital investment above \$15 million per year.

Parties’ Positions

Many parties support using some amount of transmission reserves to offset costs and reduce rates for FY 2016 and FY 2017. JP04 and Powerex argue that transmission reserves are unreasonably high and propose that BPA use \$84 million of reserves during each year of the rate period to reduce rates. JP04 Br., BP-16-B-JP04-01, at 3-9, 34; Powerex Br., BP-16-B-PX-01, at 3-5. M-S-R, which also argues that transmission reserves are unreasonably high, proposes that BPA use \$40 million of reserves per year for rate mitigation. M-S-R Br., BP-16-B-MS-01, at 3. In their joint brief, JP13 and ICNU (filing as “JP13”) propose that BPA use \$20 million per year for rate relief. JP13 Br., BP-16-B-JP13-01, at 11. As an alternative to using reserves to offset costs, WPAG suggests that BPA “increase the amount of reserves used to fund transmission capital investments during the rate period by a modest amount above the \$15 million per year proposed in BPA’s initial proposal.” WPAG Br., BP-16-B-WG-01, at 23 n.7.

BPA Staff’s Position

The Initial Proposal set rates to recover the transmission revenue requirement. Lovell *et al.*, BP-16-E-BPA-30, at 7. Other than making \$15 million per year of financial reserves for risk attributed to Transmission Services (transmission reserves) available as a means to fund capital investments in lieu of borrowing, the Initial Proposal did not use transmission reserves to reduce rates for the BP-16 rate period. Transmission Revenue Requirement Study, BP-16-E-BPA-08, at 20.

Staff opposes proposals to use reserves to offset costs and reduce rates without regard to agency reserve levels because such action would be viewed negatively by the credit rating agencies. Lovell *et al.*, BP-16-E-BPA-30, at 8-9. Using significant amounts of reserves for rate relief, such as \$84 million per year, would intentionally decrease transmission and agency reserves to levels that might not be sufficient to maintain the agency’s desired AA credit rating. *Id.* at 11. Using reserves for rate relief also would amount to an “ad hoc decision” (*i.e.*, a decision made on a rate

case-by-rate case basis without having longer-term frameworks or principles in place) that credit rating agencies may view negatively because it does not demonstrate a record of willingness to charge the rates required to recover operating and capital costs. *Id.* at 10. Finally, using reserves for the “short-term benefit” of reduced transmission rates would neglect the “long-term benefits” that robust agency financial reserves can provide to the transmission system, such as lowering BPA’s interest expense on non-Federal debt. *Id.* at 8.

Evaluation of Positions

While broadly supporting the use of reserves for rate relief, many of the parties also acknowledge the role that agency reserve levels play in BPA’s creditworthiness and the importance of maintaining a strong credit rating. JP04 Br., BP-16-B-JP04-01, at 23-24; Powerex Br., BP-16-B-PX-01, at 6; JP13 Br., BP-16-B-JP13-01, at 7; M-S-R Br., BP-16-B-MS-01, at 11. For example, Powerex states that “BPA’s agency-wide credit rating – and the means to support that credit rating – become even more important as BPA relies more heavily on its credit rating for future borrowings.” Powerex Br., BP-16-B-PX-01, at 9. JP13 recognizes the “significant potential cost implications for a credit rating downgrade.” JP13 Br., BP-16-B-JP13-01, at 7.

Maintaining BPA’s strong credit rating is very important to BPA’s long-term financial health: BPA’s credit rating is “the primary factor” that determines the interest rate on all BPA-backed bonds. Lovell *et al.*, BP-16-E-BPA-30, at 5. Credit rating agencies rate BPA’s credit each time a BPA-backed bond is publicly issued and sold by a third party. *Id.* The credit rating for any bond issuance secured by BPA payments is judged on the financial health of the entire agency. *Id.* at 4. This is true whether the bond issuance is for power facilities, such as Energy Northwest net-billed nuclear projects, or for transmission facilities under BPA’s transmission lease-purchase program. *Id.*

M-S-R “acknowledges that reserves need to be considered from an agency perspective.” M-S-R Br., BP-16-B-MS-01, at 11. Transmission reserves contribute to agency reserve levels and support BPA’s credit rating, which lowers costs and rates over the long term. Higher transmission reserves levels result in higher interest income, which offsets the revenue requirement. Lovell *et al.*, BP-16-E-BPA-30, at 23. More importantly, a strong credit rating lowers interest expense on borrowed debt. *Id.* at 8-9; Opatrny, BP-16-E-PX-01, at 20-21.

Keeping interest costs low is particularly important for transmission rates because of the lease-purchase program. Lovell *et al.*, BP-16-E-BPA-30, at 5-6. Under the program, third parties lease transmission facilities to BPA and commit the lease payments from BPA to the payment of debt service on loans and bonds. *Id.* at 5. At the end of the lease period, BPA has an option to purchase the facilities for a minimal purchase price. *Id.* Under these arrangements, BPA’s lease payments fund the debt service on the loans and bonds. *Id.* The facilities are not pledged as collateral. *Id.* at 6. Rather, the interest rates and other terms of the loans and bonds are based almost entirely on BPA’s creditworthiness. *Id.* BPA expects the program to grow significantly in the future. *Id.* If BPA’s credit rating were downgraded, the interest costs associated with the lease-purchase program could grow significantly, thereby significantly increasing the transmission revenue requirement and transmission rates over time.

Using a significant amount of reserves for rate relief could threaten BPA’s credit rating. Credit rating agencies judge a utility’s creditworthiness on a number of factors, but two factors are particularly important when determining whether to use financial reserves for rate relief: the total level of the utility’s reserves, not the level of reserves a utility attributes to a particular division, and whether the utility shows “[a] demonstrated record of willingness to charge the rates required to recover operating and capital costs[.]” Lovell *et al.*, BP-16-E-BPA-30, at 4, 8, *citing* Dan Aschenbach & John Medina, Moody’s Rating Methodology for U.S. Public Power Electric Utilities with Generation Ownership Exposure, Report No. 135299, at 9 (Nov. 9, 2011), available at [http://www.rmgfinancial.com/core/files/rmgfinancial/uploads/files/9%20US%20Public%20Power%20Utilities%20RM%202011\(1\).pdf](http://www.rmgfinancial.com/core/files/rmgfinancial/uploads/files/9%20US%20Public%20Power%20Utilities%20RM%202011(1).pdf). Using reserves to offset costs and reduce rates can undermine both of these factors.

JP04’s, Powerex’s, and M-S-R’s proposals would reduce transmission reserves and, consequently, agency reserves by substantial amounts (\$80 million to \$168 million by the end of the BP-16 rate period). Moody’s (one of the three major credit rating agencies) reports that AA-rated entities maintain between 150 and 250 days’ cash on hand, which Staff translated to between roughly \$850 million and \$1.4 billion in agency financial reserves. *Id.* at 11; Lovell, *et al.*, BP-16-E-BPA-30-E01, at 1. Powerex argues that its proposal would leave Transmission Services with sufficient transmission reserves for risk to satisfy the 150 to 250 days’ cash on hand metric. Powerex Br., BP-16-B-PX-01, at 8. As stated above, however, credit rating agencies consider total agency reserves. If BPA were to use \$80 million to \$168 million per year of transmission reserves to lower transmission rates, total agency reserves would be far lower than 150 to 250 days’ cash on hand.

Powerex and JP04 assert that using \$84 million of transmission reserves per year to mitigate the rate increase will not undermine BPA’s financial health because the 95 percent TPP standard would still be satisfied. Powerex Br., BP-16-B-PX-01, at 5; JP04 Br., BP-16-B-JP04-01, at 33-34. Powerex adds that BPA would still have sufficient reserves for Transmission Services’ within-year liquidity need. Powerex Br., BP-16-B-PX-01, at 5. However, BPA’s credit rating was downgraded after BPA filed its BP-12 rates even though the rates satisfied the 95 percent TPP standard. The downgrade was due “*in large part* because Agency reserves had declined by 36 percent between 2009 and 2010 and were expected to further decline as a result of the filed transmission rates.” Lovell *et al.*, BP-16-E-BPA-30, at 4 (emphasis added).

Furthermore, TPP is an internal BPA standard for determining whether BPA will meet its obligations to the Treasury; it is not intended as a credit-rating tool. Powerex itself observed that

[t]he TPP mechanism is not designed to be a holistic tool to evaluate financial strength and BPA’s level of creditworthiness. In other words, the TPP was designed to be used by BPA to manage its relationship with the U.S. Treasury. Another metric is needed to manage BPA’s relationship with Wall Street and creditors.

Opatrny, BP-16-E-PX-01 at 21. Drawing transmission reserves down to the lowest possible amount that satisfies the TPP standard, without regard to agency reserve levels, will not protect BPA's overall financial health or credit rating. Lovell *et al.*, BP-16-E-BPA-30, at 7, 22-23.

Powerex argues that “a modicum of consistency” with the BP-14 proceeding “warrants” the use of at least \$20 million of reserves per year, because BPA used \$20 million of transmission reserves to reduce rates in the BP-14 rate case. Powerex Br., BP-16-B-PX-01, at 5; Powerex Br. Ex., BP-16-R-PX-01, at 11-12. JP04 similarly argues that BPA's use of reserves to reduce rates in the BP-14 rate case “demonstrated [BPA's] ability and willingness” to use transmission reserves to mitigate rate increases.” JP04 Br., BP-16-B-JP04-01, at 29-30. JP13 also proposes that BPA use \$20 million per year for rate relief. JP13 Br., BP-16-B-JP13-01, at 11.

Powerex questions “how much reserves are enough” to support the agency credit rating and challenges BPA's refusal to use even a modest amount of reserves. Powerex Br. Ex., BP-16-R-PX-01, at 8-9. As explained above, in the absence of a long-term financial reserves policy or formal mechanism to use transmission reserves, use of reserves to mitigate a proposed rate increase would not demonstrate the record that credit rating agencies look for when assessing creditworthiness. Lovell *et al.*, BP-16-E-BPA-30, at 8-11.

JP04 argues that assertions in the Draft ROD about what “could” happen to BPA's credit rating are speculative. JP04 Br. Ex., BP-16-R-JP04-01, at 4-5. Despite acknowledging the measurable risks, Powerex also downplays the credit rating concerns. Powerex Br., BP-16-B-PX-01, at 9; Powerex Br. Ex., BP-16-R-PX-01, at 11. Powerex states that risks related to the power business line also contributed to the credit rating downgrade after the BP-12 rates were filed. Powerex Br. Ex., BP-16-R-PX-01, at 11 & n.40. Powerex adds that BPA's credit rating was not downgraded after the BP-14 rate case, when BPA used \$20 million of reserves per year to reduce rates. *Id.* at 9-10.

It is true that it cannot be stated with absolute certainty whether BPA's credit rating would be downgraded if transmission reserves were used to reduce rates in this proceeding. Because the effects of a downgrade would be so significant, however, the agency must proceed with extreme caution. Staff provided compelling testimony that the use of reserves on an ad hoc basis could compromise BPA's standing with the credit rating agencies because it would reduce agency reserve levels and would not demonstrate a record of willingness to charge rates required to recover costs. Lovell *et al.*, BP-16-E-BPA-30, at 4, 8-9, & 22-23. The primary concern in this proceeding, therefore, is that credit rating agencies could view the decision to use transmission reserves for rate mitigation as demonstrating a lack of commitment to make difficult financial decisions in the face of pressure by rate case parties. *Id.* at 8. It makes particular sense to defer any use of reserves in this case since BPA will be working with the parties after the rate case to develop a financial reserves policy. In future rate cases BPA will be able to apply that policy to determine whether to use reserves and will not have to even consider using them to reduce rates on an ad hoc basis.

JP04 argues that the use of reserves in this case would not be “ad hoc” because JP04 proposed transmission risk mitigation measures and policy objectives, including a dividend distribution

clause (DDC) (under which rates are adjusted downward only if reserves exceed a set threshold). JP04 Br. Ex., BP-16-R-JP04-01, at 4-5. As explained in Issue 4.2.2.2, however, JP04's proposal would threaten BPA's credit rating because it significantly lowers the agency reserve level. Neither the proposed risk mitigation measures and policy objectives nor the DDC are adopted in this ROD; therefore, use of reserves for rate relief would be "ad hoc." Moreover, the question of exactly what risk measures and policies to adopt is a significant one that would benefit from a more robust regional discussion. It would be hasty to simply adopt a proposal made in rebuttal testimony without this further discussion.

Powerex argues that Staff's concern about the credit rating is contradicted by Staff's proposed DDC, which could reduce reserve levels. Powerex Br., BP-16-B-PX-01, at 7. Powerex adds that Staff "does not express concerns over BPA's credit rating should the DDC trigger." *Id.* Unlike the ad hoc use of reserves during a rate case to mitigate rate increases, however, a formal DDC mechanism reflects a considered approach to the use of reserves with explicit criteria for when to use reserves and how much to use. Lovell *et al.*, BP-16-E-BPA-30, at 10.

Powerex argues that BPA can use reserves to lower transmission rates because the proposed CRAC (annual upward adjustment in rates if reserves are below a threshold) mechanism will have a positive impact on BPA's credit rating. Powerex Br., BP-16-B-PX-01, at 6-7. However, as discussed in Issue 4.2.2.2, no CRAC is being adopted in this rate period.

As an alternative to using reserves to offset costs and reduce rates, WPAG proposes to use a modest additional amount of reserves to fund transmission capital investments during the rate period beyond the \$15 million per year in Staff's Initial Proposal. WPAG Br., BP-16-B-WG-01, at 23 n.7. WPAG argues that its proposal "will preserve limited borrowing authority, reduce BPA's long-term debt-related costs, and provide long-term benefits to the transmission system and transmission rate-payers." *Id.* On the one hand, WPAG's proposal is consistent with the Initial Proposal's use of \$15 million of reserves for capital expenditures, which does not threaten BPA's credit rating. Lovell *et al.*, BP-16-E-BPA-30, at 7.

On the other hand, WPAG's proposal would further reduce transmission and agency reserve levels, which credit rating agencies could view negatively. As discussed in Issue 4.2.2.2, many parties ask that BPA hold workshops after the conclusion of the BP-16 rate proceeding to discuss and develop a long-term financial reserves policy. The soundest course would be to develop this policy before using additional reserves for rate relief.

Finally, M-S-R argues that "intergenerational equity" requires that BPA use transmission reserves for rate relief in the BP-16 rate period; since current customers "funded the excess," current customers should receive the benefit. M-S-R Br., BP-16-B-MS-01, at 4. As discussed in Issue 4.2.2.3 below, BPA must establish the lowest possible rates consistent with sound business principles. During the decade over which M-S-R claims BPA accumulated excess transmission reserves, no party argued that BPA's transmission rates failed to meet this standard. To the contrary, most of the transmission cases since 1996 have been settled, with customers agreeing to the rates.

As the Administrator stated in the BP-14 ROD, customers during prior rate periods (1996 to 2013) have no right to the accumulation of reserves during those periods because the rates were set to achieve cost recovery and customers agreed to the rates in settlements. BP-14 ROD, BP-14-A-03, at 141. In addition, the rates did not contain any mechanism requiring that revenues in excess of costs be returned to customers. *Id.* The Administrator also stated that

embedded in BPA's origins was the understanding that any accumulation of reserves would be put to use for the long-term benefit of the system, and ultimately, ratepayers.

Id. Moreover, M-S-R ignores the benefits that current transmission customers receive from maintaining robust transmission reserves during the BP-16 rate period, such as higher interest income to offset the revenue requirement.

Decision

Financial reserves available for risk attributed to Transmission Services will not be used to mitigate the proposed rate increase, or fund transmission capital investment above \$15 million per year.

Issue 4.2.2.2

Whether transmission risk mitigation objectives and CRAC and DDC mechanisms should be adopted.

Parties' Positions

JP04 proposes that BPA adopt transmission risk objectives and CRAC and DDC mechanisms similar to the risk objectives and mechanisms in power rates. JP04 Br., BP-16-B-JP04-01, at 20. Under JP04's proposal, the DDC mechanism would trigger when transmission reserves exceed \$500 million. *Id.*; Holland *et al.*, BP-16-E-JP04-08, at 5. Powerex supports JP04's proposal and argues that a CRAC mechanism would reinforce BPA's credit rating. Powerex Br., BP-16-B-PX-01, at 6-7.

JP04, Powerex, and M-S-R argue that Staff's proposal for a CRAC and DDC (made in rebuttal testimony) would result in transmission customers disproportionately supporting the agency credit rating. JP04 Br., BP-16-B-JP04-01, at 13-16; Powerex Br., BP-16-B-PX-01, at 10, 12, 14-18; M-S-R Br., BP-16-B-MS-01, at 9. Specifically, these parties oppose tying a transmission DDC mechanism to agency reserve levels when the power DDC mechanism is not tied to agency reserves. JP04 Br., BP-16-B-JP04-01, at 21-26; Powerex Br., BP-16-B-PX-01, at 11, 18; M-S-R Br., BP-16-B-MS-01, at 9-10. M-S-R asserts that the proposed DDC mechanism would "continue the over collection of financial reserves for transmission." M-S-R Br., BP-16-B-MS-01, at 9.

JP04 and M-S-R also oppose Staff's proposal to apply 50 percent of the amount above the DDC threshold to debt retirement. JP04 Br., BP-16-B-JP04-01, at 26-28; M-S-R Br., BP-16-B-MS-01, at 10. Both parties assert that Staff's proposal would violate statutory obligations to ensure that rates are sufficient to repay the Federal investment over a reasonable number of years. JP04 Br., BP-16-B-JP04-01, at 28; M-S-R Br., BP-16-B-MS-01, at 10.

JP04 and Powerex support the allocation of the Treasury Facility (an arrangement allowing BPA to borrow money from the U.S. Treasury on a short-term basis) to support Transmission Services in general but argue that it is unclear whether Staff's proposal, which allocated some of the Treasury Facility to Transmission Services to cover transmission within-year liquidity needs, is equitable between business lines. JP04 Br., BP-16-B-JP04-01, at 10-11; Powerex Br., BP-16-B-PX-01, at 5.

JP13, NRU, WPAG, JP17, and PNGC argue that the Administrator should not adopt Staff's proposal because it makes a significant change to the agency's policy on use of reserves very late in the rate case, was unexpected, is incomplete, and could pre-judge the outcome of further discussions on BPA's financial reserve policies. JP13 Br., BP-16-B-JP13-01, at 3-4, 7, 11-12; NRU Br., BP-16-B-NR-01, at 9, 16-18; WPAG Br., BP-16-B-WG-01, at 23; JP17 Br., BP-16-B-JP17-01, at 1-2; PNGC Br., BP-16-B-PN-01, at 6-7. NRU argues that BPA gave parties inadequate due process on this issue because "it is nearly impossible to quantify or qualitatively consider the impacts" of Staff's proposal. NRU Br., BP-16-B-NR-01, at 15-16.

JP13 alleges that BPA gave "inadequate notice" of the Staff proposal because BPA indicated in pre-rate case workshops that it did not anticipate using financial reserves for rate relief during the BP-16 rate period and neither the Federal Register notice nor the Initial Proposal mentioned or proposed changes to transmission reserves policies. JP13 Br., BP-16-B-JP13-01, at 4, 7-8. JP13 asserts that proposing the policy for the first time in rebuttal testimony "did not allow for the transparent public process that a revision of BPA's financial policies warrants." *Id.* at 7.

All parties that commented on this issue suggest that BPA hold workshops at the conclusion of the BP-16 proceeding to discuss and develop an agency financial reserves policy. JP04 Br., BP-16-B-JP04-01, at 11,18; Powerex Br., BP-16-B-PX-01, at 20; M-S-R Br., BP-16-B-MS-01, at 8-11; JP13 Br., BP-16-B-JP13-01, at 7; NRU Br., BP-16-B- NR-01, at 9; WPAG Br., BP-16-B-WG-01, at 23; JP17 Br., BP-16-B-JP17-01, at 1-2; PNGC Br., BP-16-B-PN-01, at 6-8.

BPA Staff's Position

In rebuttal testimony, Staff proposes transmission risk objectives and CRAC and DDC mechanisms similar to the ones in JP04's proposal but with several major differences. Lovell *et al.*, BP-16-E-BPA-30, at 1, 11. Staff includes as a transmission risk objective maintenance of the agency's AA credit rating and did not include an objective stating a preference for lower adjustable rates over higher, more stable rates. *Id.* at 2-3. Staff also includes a DDC mechanism that would trigger if both transmission reserves and agency reserves exceed a specific threshold. *Id.* at 11. Staff proposes to apply 50 percent of the amount above the DDC threshold to rate relief and the other 50 percent to debt retirement. *Id.* at 13. In addition, Staff proposes to allocate \$100 million of the Treasury Facility to transmission to support Transmission Services'

within-year liquidity needs. *Id.* at 16. Staff did not propose parallel risk objectives and CRAC and DDC mechanisms for power rates, but proposes workshops to be held before the BP-18 rate case to further discuss and develop parallel risk objectives and a CRAC and DDC mechanism for both power and transmission. *Id.* at 9, 12.

Staff did not address the procedural issues because they were raised after Staff's rebuttal testimony was submitted.

Evaluation of Positions

Both JP04's and Staff's proposals include the formal structure of a DDC but differ on the level of reserves that would trigger the DDC. Under JP04's proposal, the DDC would trigger when transmission reserves exceed \$500 million. JP04 Br., BP-16-B-JP04-01, at 20. Under Staff's proposal, the DDC would trigger when transmission reserves exceed \$500 million *and* agency reserves exceed a certain amount: \$800 million in July 2016 (for applying the DDC to FY 2016 rates) and \$900 in September 2016 (for applying the DDC to FY 2017 rates). Lovell *et al.*, BP-16-E-BPA-30, at 12, & Att. 1, at 8. The formal structure of a DDC would likely mitigate some of the credit rating risk associated with applying reserves to reduce rates. *Id.* at 10. A DDC mechanism reflects a considered approach for using reserves that is intended to be applied consistently over time, with explicit criteria for when to use reserves and how much to use. *Id.* It is also important that the DDC mechanism be structured to maintain sufficient agency reserve levels to support the agency's credit rating. *Id.* at 4, 11.

JP04's proposal could threaten BPA's credit rating because its proposed DDC mechanism could significantly reduce transmission reserve levels without regard to any minimum threshold for agency reserves. Although Staff's proposal is preferable to JP04's proposal in this respect, no party supports it. Parties' concerns include the completeness and equity of Staff's proposal, inadequate procedure, and potential impacts on future policy development. All parties that addressed this issue propose that the Administrator reject Staff's proposal and, instead, initiate a public process to discuss and develop BPA's long-term financial reserves policy after the BP-16 rate case.

The proposal to initiate a public process has merit and will be adopted. Adopting risk objectives and implementing a DDC and CRAC are significant decisions. As the parties note, Staff's proposal was made late in the proceeding. A more considered approach would be preferable. Holding workshops after the conclusion of the BP-16 rate proceeding is a reasonable alternative to adopting Staff's proposal and will provide a robust opportunity to engage customers in the development of a long-term financial reserves policy.

Powerex suggests principles to guide workshop discussions. Powerex argues that each business line should bear its respective weight for BPA's overall credit rating and that the Treasury Facility should be apportioned between the business lines by an appropriate metric. Powerex Br., BP-16-B-PX-01, at 19; Powerex Br. Ex., BP-16-R-PX-01, at 14. Powerex also suggests that the DDC thresholds, measures used to determine the triggering of the DDC or CRAC, and the DDC distributions should be applied comparably between the business lines. Powerex Br., BP-16-B-PX-01, at 19; Powerex Br. Ex., BP-16-R-PX-01, at 14. Because Powerex first

provided these principles in its surrebuttal testimony, no party responded to them and Staff has not had an opportunity to respond to them. Therefore, rather than adopt principles in this Record of Decision, BPA Staff and the parties should work together to develop guiding principles for the workshop discussions.

Powerex asks whether the 150 to 250 days' cash on hand metric is being adopted as a policy regarding the threshold to determine when to use reserves. Powerex Br. Ex., BP-16-R-PX-01, at 8. This metric is not being adopted as a policy. The appropriate metrics will be an issue in the discussions that follow the rate case.

Powerex also asks the Administrator to adopt Staff's proposal to allocate \$100 million of the \$750 million Treasury Facility to the within-year liquidity needs associated with Transmission Services. Powerex Br., BP-16-B-PX-01, at 18; Powerex Br. Ex. BP-16-R-PX-01, at 15-16. There is no compelling reason to adopt this proposal at this time. Transmission reserves are "currently robust" and can supply the transmission within-year liquidity needs for FY 2016 and FY 2017. Lovell *et al.*, BP-16-E-BPA-30, at 15. The allocation of Treasury Facility can be discussed in the workshops.

As stated above, JP04's DDC is similar to the DDC Power Services has established. Power Services' DDC mechanism is tied only to business line (in that case power) reserve levels. JP04 Br., BP-16-B-JP04-01, at 18; Lovell *et al.*, BP-16-E-BPA-30, at 12. Although JP04's DDC threatens BPA's credit rating, it should be noted that the DDC in power rates does not. Transmission reserves are robust. Lovell *et al.*, BP-16-E-BPA-30, at 22. If power reserves grew sufficiently to trigger the DDC (Staff does not think this a likely event), agency reserves would be "very robust." *Id.* at 12. In that case, reducing agency reserves in the amount triggered "should present little jeopardy to BPA's credit rating." *Id.*

Finally, given the decision, the procedural issues are moot. Nevertheless, it should be noted that, although the time for parties' response was limited in this case, several parties objected simply to the fact that Staff made its proposal, which they viewed as an unexpected and significant change, in rebuttal testimony. JP13 Br., BP-16-E-JP13-01, at 7-9; PNGC Br., BP-16-B-PN-01, at 6-7; M-S-R Br., BP-16-B-MS-01, at 7-8; JP17 Br., BP-16-B-JP17-01, at 2. Staff did so in response to proposals made by parties to the case. Lovell *et al.* BP-16-E-BPA-30, at 1, 10-11, *citing* Holland *et al.*, BP-16-E-JP04-01, at 17-21; Opatrny, BP-16-E-PX-01, at 15-16, 23-24; Arthur, BP-16-E-MS-01, at 1-2. The very purpose of parties' testimony is to convince BPA Staff, and ultimately the Administrator, to pursue a particular course, often one different from that originally proposed. If BPA Staff could never incorporate parties' ideas into its rebuttal testimony or make new proposals based on the parties' arguments, there would be little point to the parties' testimony. Therefore, Staff's efforts were consistent with the spirit of the rate case.

Decision

Transmission risk mitigation objectives and CRAC and DDC mechanisms will not be adopted. After conclusion of the rate proceeding, BPA will engage the region regarding a financial reserves policy. Staff and interested stakeholders should work together at the outset of the workshops to identify the framework and agenda for the discussions.

Issue 4.2.2.3

Whether either the level of transmission reserves or the fact that transmission TPP is above 95 percent indicates that the proposed transmission rates are too high.

Parties' Positions

JP04, Powerex, and M-S-R characterize the levels of transmission reserves as “unreasonably high” and “excessive.” JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3; JP04 Br. Ex., BP-16-R-JP04-01, at 9; Powerex Br. Ex., BP-16-R-PX-01, at 7, 12; M-S-R Br. Ex., BP-16-R-MS-01, at 2. The parties claim that transmission reserve levels are unreasonable because the actual levels of reserves at the end of prior rate periods have exceeded the forecast levels. JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3; Powerex Br. Ex., BP-16-R-PX-01, at 7, 12. JP04 also argues that transmission reserve levels are unreasonable because transmission reserves represent approximately 50 percent of transmission operating expenses and revenues, whereas power reserves represent approximately 14 percent of power operating expenses and revenues. JP04 Br., BP-16-B-JP04-01, at 8-9; JP04 Br. Ex., BP-16-R-JP04-01, at 5-6. Powerex and M-S-R make similar arguments. Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3; M-S-R Br. Ex., BP-16-R-MS-01, at 2.

JP04 and Powerex argue that a TPP of 100 percent shows that reserves are too high. JP04 Br., BP-16-B-JP04-01, at 5; Powerex Br., BP-16-B-PX-01, at 3. JP04 adds that, because the TPP for Transmission Services “significantly exceeds” 95 percent, BPA’s proposed transmission rates are not the lowest possible rates consistent with sound business principles. JP04 Br., BP-16-B-JP04-01, at 33.

BPA Staff's Position

Although transmission reserves are above the absolute minimum necessary to meet the 95 percent TPP standard, exceeding the TPP standard does not mean transmission reserves are unreasonably high. Lovell *et al.*, BP-16-E-BPA-30, at 22-23. Since no PNRR was added to the revenue requirement to increase financial revenues during the rate period to achieve the TPP goal, the rates are set at the lowest level sufficient to meet the revenue requirement. *Id.* at 20-21.

Evaluation of Positions

The parties argue that transmission reserves are unreasonably high because the actual levels of reserves at the end of prior rate periods have exceeded forecasts. JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3; Powerex Br. Ex., BP-16-R-PX-01, at 7, 12. Powerex adds that “BPA’s reserve forecasts have typically underestimated the actual levels by approximately \$90 million per year.” Powerex Br., BP-16-B-PX-01, at 3; Powerex Br. Ex., BP-16-R-PX-01, at 12. Powerex also cites JP07’s testimony to argue that BPA’s interest expense forecast is too high. *Id.* at 7. However, the FY 2016–2017 rates are set to recover forecast rate period costs and nothing more. Staff’s forecasts of revenues and expenses are based on the best available information. Lennox *et al.*, BP-16-E-BPA-25, at 2. By its nature forecasting is imperfect, and actual results will differ from forecasts.

The parties also argue that transmission reserves are unreasonable because they are a greater percentage of transmission operating expenses and revenues than power reserves are of power operating expenses and revenue. JP04 Br., BP-16-B-JP04-01, at 8-9; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3; JP04 Br. Ex., BP-16-R-JP04-01, at 5-6; M-S-R Br. Ex., BP-16-R-MS-01, at 2. There is no reason to conclude from this fact that transmission reserves are too high—as opposed to power reserves being too low—and in any case that comparison has no effect on rates. Lovell *et al.*, BP-16-E-BPA-30, at 23.

M-S-R argues that transmission reserves should be used to reduce rates because the Administrator acknowledged in the Draft ROD that it would be appropriate to use power reserves to reduce rates if they were as robust as transmission reserves. M-S-R Br. Ex., BP-16-R-MS-01, at 2. The Draft ROD did not make this statement. Instead, it said that, if power reserves grew sufficiently to trigger the DDC, agency reserves would be very robust. BP-16 Draft ROD, BP-16-A-01, at 83-84. Thus, the Draft ROD addressed a situation in which both business lines enjoyed robust reserves, in which use of reserves would not jeopardize the overall level of agency reserves. That is not the case right now.

Regarding the arguments that the TPP level indicates that reserves and rate levels are too high, the TPP standard is a “policy tool” to help ensure that Treasury payments can be made in full and on time during the rate period. Lovell *et al.*, BP-16-E-BPA-30, at 23. The Administrator addressed the same issue in the BP-14 rate case, explaining that the 95 percent TPP standard is not intended to be a maximum level and does not require BPA to use reserves to offset costs and reduce rates when the level of reserves exceeds the minimum required to meet the standard. BP-14 ROD at 129-32. The TPP standard was not designed to be a policy tool to determine when reserves should be used to reduce rates.

Critically, the TPP level has no impact on the FY 2016–2017 Initial Proposal rates because they include no PNRR. Lovell *et al.*, BP-16-E-BPA-30, at 20. PNRR is added if the risk analysis tests indicate that there will be insufficient reserves on hand during the rate period to meet the 95 percent standard. *Id.* These tests are performed after rates are set at the minimum level sufficient to meet the revenue requirement. *Id.* If the tests indicate that the TPP standard is below 95 percent, PNRR is added to the revenue requirement until the 95 percent TPP standard is met. *Id.* No PNRR was added to the revenue requirement in the Initial Proposal. Therefore, rates are not higher because TPP is above 95 percent. *Id.* at 21.

JP04 argues that the level of transmission reserves and the TPP level indicate that the proposed rates are not the lowest possible rates consistent with sound business principles. JP04 Br., BP-16-B-JP04-01, at 33; JP04 Br. Ex. BP-16-R-JP04-01, at 9. JP04 overstates the statutory mandate. Section 9 of the Transmission System Act provides that rate schedules for the sales of electric power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established “with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. § 838g. Similarly, section 5 of the Flood Control Act of 1944 provides that BPA shall dispose of power “in such manner as to encourage the most

widespread use thereof at the lowest possible rates to consumers consistent with sound business principles.” *Id.* § 825s.

As noted in the BP-12 and BP-14 Administrator’s Records of Decision, the Ninth Circuit Court of Appeals has found that the obligation to “encourag[e] ... the lowest possible rates to consumers” is not a mandate to set the lowest rates possible without regard to any other business or legal principle. 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, Administrator’s Final Record of Decision, BP-12-A-02, at 127 (July 2011) (BP-12 ROD); BP-14 ROD at 124-25. As the Court has explained:

[T]he statutes do not dictate that BPA always charge the lowest possible rates. 16 U.S.C. § 838g directs that rates be set “with a view to encouraging ... the lowest possible rates to consumers” The words “with a view to encouraging” do not constitute a statutory command that the prices charged to consumers always be the lowest possible. Moreover, nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the “lowest possible rates” standard ... were accepted, the discretion that Congress vested in the Administrator would be eliminated.

In addition, the direction to charge the lowest possible rates is tempered by the addition of the clause “consistent with sound business principles.” 16 U.S.C. § 838g.

BP-12 ROD at 127-28, *quoting Cal. Energy Comm’n v. Bonneville Power Admin.*, 909 F.2d 1298, 1308 (9th Cir. 1990); BP-14 ROD at 124-25. Whether BPA’s rates have been set with “a view to encouraging the widest possible diversified use ... at the lowest possible rates to consumers consistent with sound business principles,” 16 U.S.C. § 838g, “is a matter for BPA to decide, subject to judicial review.” *Bonneville Power Admin.*, 32 FERC ¶ 61,014, at 61,053 (1985). It is not a matter for Federal Energy Regulatory Commission review. *Id.*; *see also* 16 U.S.C. § 839e(a)(2) (stating the standards for the Commission’s review of BPA’s rates).

In response to similar arguments raised during the BP-14 case, the Administrator stated:

The Ninth Circuit has held that the obligation to operate according to “sound business principles” affords BPA discretion to operate with a business-oriented philosophy. *Pub. Power Council v. BPA*, 442 F.3d 1204 (9th Cir. 2006) (PPC); *Ass’n of Pub. Agency Customers, Inc. v. BPA*, 126 F.3d 1158, 1171 (9th Cir. 1997) (APAC); *Dep’t of Water & Power of Los Angeles v. BPA*, 759 F.2d 683 (9th Cir. 1985). Congress “has delegated to BPA the discretion to determine “how best to further BPA’s business interests consistent with its public mission.”” *Alcoa, Inc. v. Bonneville Power Admin.*, 698 F.3d 774, 789 (9th Cir. 2012) (quoting APAC, 126 F.3d at 1171).

BP-14 ROD at 125.

Moreover, BPA has other rate directives. The first directive stated in the Northwest Power Act is the requirement that BPA “establish ... rates ... to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power.” 16 U.S.C. § 839e(a)(1). Ensuring BPA’s cost recovery is also the Commission’s primary charge. The Commission reviews BPA’s rates under three standards, the first of which is that the rates “are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator’s other costs.” *Id.* § 839e(a)(2)(A). The Administrator has concluded that recovery of costs is BPA’s primary rate mandate: “Overall cost recovery is the paramount objective of BPA’s rate directives.” Administrator’s Record of Decision, 1996 Final Rate Proposal, WP-96-A-02, at 393 (June 1996).

Significantly, under the Transmission System Act the Administrator is also required to establish rates not only to recover the cost of producing and transmitting electric power but also “at levels to produce such additional revenues ... to pay when due the principal of ... and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.” 16 U.S.C. § 838g.

Finally, in the 1993 Administrator’s Record of Decision, the Administrator evaluated arguments that BPA should reduce rate increases to be competitive. 1993 ROD at 11. In response to these arguments, the Administrator stated:

If, viewed as a whole, all reasonable rate actions have been taken to establish the rates as low as possible consistent with sound business principles – and here it must be understood that decisions on many issues trade off and factor into decisions on other issues – the consequence is that the rates are the lowest consistent with sound business principles.

Id. at 14. As shown above, the trade-off of using reserves for rate mitigation is that it poses increased risk of a credit rating downgrade and consequent increased financing costs. As also noted above, the public workshops to be held after the rate case will allow BPA to develop a more considered policy for use of reserves.

JP04 argues that the Draft ROD “does not and cannot demonstrate that transmission rates must always be set at a level projected to generate an amount equal to the transmission revenue requirement.” JP04 Br. Ex., BP-16-R-JP04-01, at 9. The Draft ROD did not attempt this demonstration. First, BPA is using \$15 million per year of reserves in this rate case to fund capital projects in lieu of borrowing for that amount or recovering that amount in the revenue requirement. Transmission Revenue Requirement Study, BP-16-FS-BPA-08, at 20. Second, BPA will be conducting a process after this rate case specifically to adopt a policy on the use of reserves for rate relief and other purposes. Thus, the agency agrees that under appropriate conditions transmission rates can be set such that rates together with an appropriate amount of reserves equals the transmission revenue requirement.

Decision

The level of transmission reserves and the fact that transmission TPP is above 95 percent does not indicate that the proposed rates are too high.

Issue 4.2.2.4

Whether maintaining transmission reserves for risk to support BPA's credit rating is a cost of the Federal transmission system.

Parties' Positions

Powerex and JP04 characterize the maintenance of transmission reserves to support the agency credit rating as a cost that must be equitably allocated between power and transmission rates. Powerex Br., BP-16-B-PX-01, at 11-12; JP04 Br., BP-16-B-JP04-01, at 20; Powerex Br. Ex., BP-16-R-PX-01, at 3-6; JP04 Br. Ex., BP-16-R-JP04-01, at 12-14. M-S-R agrees. M-S-R Br. Ex., BP-16-R-MS-01, at 3-4. Powerex asserts that “BPA disproportionately relies upon Transmission reserves to support its credit rating” and claims that there is a measurable cost associated with this reliance. Powerex Br., BP-16-B-PX-01, at 11-13. Powerex argues that the “disproportionate reliance on Transmission reserves ... runs afoul of FERC’s prohibition of cross-subsidization between the business lines.” *Id.* at 12. JP04 adds that transmission rates and reserves “are higher than they should be” and power rates and reserves are “lower than they should be.” JP04 Br. Ex., BP-16-R-JP04-01, at 2.

BPA Staff's Position

Staff did not specifically address this issue, but stated that transmission reserves do not add costs to transmission rates and, instead, result in higher interest income, which offsets the revenue requirement. Lovell *et al.*, BP-16-E-BPA-30, at 23.

Evaluation of Positions

Section 7(a)(2) of the Northwest Power Act and section 10 of the Transmission System Act require BPA to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the system. 16 U.S.C. §§ 839e(a)(2) & 838h. The Commission approves BPA’s rates only upon a finding that they satisfy this standard. In determining whether costs are equitably allocated, the Commission requires a separate accounting of power and transmission costs and revenues so that the Commission can determine that “(1) transmission revenues are only used to repay transmission costs; (2) costs assigned to transmission are only transmission related costs; and (3) any deficiencies or surpluses in transmission revenues are being tracked and collected or credited to the appropriate customer class.” *U.S. Dep’t of Energy–Bonneville Power Admin.*, 25 FERC ¶ 61,140, at 61,375-76 (1983).

The crux of Powerex’s argument is that transmission reserve levels support a strong agency credit rating that benefits both Transmission Services and Power Services. Neither Powerex nor JP04 has argued that the transmission rates violate any of the above tests. There is no evidence, nor any reason to believe, that transmission reserve levels impose any costs on Power Services or

Transmission Services or have any effect on power rates. Transmission reserve levels do have an effect on transmission rates because they earn interest income that offsets part of the transmission revenue requirement and thereby reduces transmission rates. Lovell *et al.*, BP-16-E-BPA-30, at 23.

Powerex argues that transmission reserves levels subsidize Power Services and that this subsidization has “a real and quantifiable cost.” Powerex Br., BP-16-B-PX-01, at 12; Powerex Br. Ex., BP-16-R-PX-01, at 3. Powerex characterizes the high level of transmission reserves as providing a “service” to Power Services by effectively lending it money to support its creditworthiness. *Id.* at 6. Powerex avers that Transmission Services would “merit a higher credit rating than Power Services” because Transmission Services has “over 400 days’ cash on hand” and Power Services has “only 50 days’ cash on hand.” Powerex Br., BP-16-B-PX-01, at 13. Powerex then estimates that Power Services’ lower credit rating could result in \$10 million to \$30 million of increased interest expense per year. *Id.*; Powerex Br. Ex., BP-16-R-PX-01, at 5.

The underlying premise to Powerex’s argument is that there is a separate credit rating for each business line. There is not; Power Services does not itself have a credit rating. As discussed in Issue 4.2.2.1, credit rating agencies do not rate each business line separately based on that business line’s reserve levels. Lovell *et al.*, BP-16-E-BPA-30, at 4. Credit rating agencies consider BPA as a whole. *Id.*

More importantly, none of this analysis demonstrates an increased cost to Transmission Services. No party has offered any evidence that the proposed transmission rates over-recover transmission costs. No power costs or revenues have been allocated to Transmission Services; no transmission costs or revenues have been allocated to Power Services. No party has argued otherwise. The alleged balance or imbalance of power and transmission reserves has no bearing on the equitable allocation of the costs of the Federal transmission system.

JP04 argues that transmission reserves are a “cost” of the Federal transmission system because of the inclusion of Planned Net Revenue for Risk (PNRR) in the transmission revenue requirement. JP04 Br. Ex., BP-16-R-JP04-01, at 12. PNRR is added to the revenue requirement if financial reserves are insufficient to satisfy the TPP standard. Lovell *et al.*, BP-16-E-BPA-30, at 20-21. The transmission revenue requirement includes no PNRR. Therefore, reserves are not a cost of the transmission system.

JP04 argues, however, that transmission reserves for risk are a cost of the Federal transmission system in this rate case because in the past BPA has included PNRR in transmission rates. JP04 Br. Ex., BP-16-R-JP04-01, at 12. BPA is establishing rates to recover the revenue requirement in the FY 2016-2017 rate period. Inclusion of PNRR in past rates does not increase the revenue requirement or costs in this rate case. It has no effect on these rates, and therefore PNRR is not a cost in this rate case.

JP04 suggests that BPA should add PNRR in the power revenue requirement to generate additional power reserves for risk. JP04 Br. Ex., BP-16-R-JP04-01, at 14. In such case the

agency would have adequate reserves and BPA could use transmission reserves to reduce rates. *Id.* However, the combination of existing power reserves and the Treasury Facility is adequate to mitigate Power Services' risks; there is no need for PNR. Moreover, the power and transmission rates are set to recover the power and transmission revenue requirements, respectively. The relatively higher level of transmission reserves is an artifact of past transmission and power rate-setting and the financial impacts on transmission reserves and on power reserves of real-world events as they unfolded. Although forecasts were not always precise, in each case rates were set to recover costs based on the best available information. In no case were transmission rates set based on their effect on power rates, and power rates should not be set based on their effect on transmission rates.

M-S-R argues that the Draft ROD inappropriately concluded that maintaining transmission reserves is not a cost of the Federal transmission system because the transmission rates are higher than they would have been had reserves been used to mitigate the rate increase. M-S-R Br. Ex., BP-16-R-MS-01, at 3-4. That does not mean, however, that the existence of transmission reserves increases rates or adds to costs; it does not. Transmission rates are being established to recover transmission costs and no more.

Finally, both business lines contribute to and benefit from the agency's strong credit rating. Transmission customers, in particular, benefit from the agency's strong credit rating because of the lease-purchase program. As discussed in Issue 4.2.2.1, the interest rates and other terms of the loans and bonds associated with the lease-purchase program are based almost entirely on BPA's creditworthiness. Lovell *et al.*, BP-16-E-BPA-30, at 6. BPA expects the program to grow significantly in the future; eventually it could finance as much as half of Transmission Services' planned capital investments. *Id.* Powerex and M-S-R argue that the Draft ROD ignores the benefits that Power Services receives from the agency credit rating. Powerex Br. Ex., BP-16-R-PX-01, at 3-4; M-S-R Br. Ex., BP-16-R-MS-01, at 4. It is true that the agency is evaluated as a whole by the credit rating agencies. As discussed above, however, rates for each business line are based on costs attributable to that business line. That is the premise of BPA's statutes and of BPA's separate accounting. As also discussed above, it would be inappropriate to set rates for one business line in order to be able to reduce rates for the other business line.

Decision

Maintaining transmission reserves for risk to support the agency credit rating is not a cost of the Federal transmission system.

4.3 Transmission Rate Design

BPA's transmission rate design process involves determining the overall costs of the transmission system, allocating those costs among transmission customers, and calculating the proposed transmission rates for BPA's wholesale transmission products and services for the rate period, FY 2016 and 2017. The Transmission Rates Study and Documentation, BP-16-FS-BPA-07, includes the results of this process and demonstrates that the rates for BPA's wholesale

transmission services for FY 2016–2017 have been developed consistent with BPA’s statutory and contractual obligations and will recover the transmission revenue requirement.

This section of the ROD addresses transmission rate design issues raised by the parties, including the BP-14 O&M error, cost allocation for certain reliability compliance activities, the Southern Intertie hourly non-firm rate, the oversupply rate, elimination of the Montana Intertie rate, , and a request for workshops to discuss Network segment cost allocation.

4.3.1 BP-14 O&M Error

After the end of the BP-14 rate case, BPA Staff discovered that it had allocated costs in the segmentation study based on historical averages of O&M costs that were developed for the BP-12 rate case. BPA did not under-recover its costs, but instead unintentionally shifted costs between segments. The Network and Eastern Intertie segments were allocated more than their correct share of O&M costs, while the Generation Integration, Southern Intertie, Utility Delivery, and DSI Delivery segments were allocated less than their correct share (as explained below, the under-allocation of costs did not reduce the rates for the Utility Delivery and DSI Delivery segments). Staff proposed to correct the error in this rate case. Fredrickson *et al.*, BP-16-E-BPA-14, at 14-15.

Issue 4.3.1.1

Whether BPA should correct the misallocation of O&M costs made in the BP-14 rate case.

Parties’ Positions

Iberdrola argues that correction of the error would be prohibited as retroactive ratemaking. Iberdrola Br., BP-16-B-IR-01, at 11. Iberdrola also argues that the correction would not adjust fairly for the error because the Southern Intertie segment would be allocated \$6 million more annually while the Utility Delivery and DSI segments would be unaffected. Wrigley and Kester, BP-16-E-IR-01, at 16. According to Iberdrola, BPA leaves other errors of similar or greater magnitude uncorrected, and correction of the BP-14 error would set “a troubling precedent” and encourage parties to argue for future “corrections” whenever actual results deviate from rate case forecasts. *Id.* at 17-18.

JP08 also argues that correction of the error would be illegal retroactive ratemaking. JP08 Br., BP-16-B-JP08-01, at 8. JP08 argues that BPA should not correct the error because it is important to maintain the stability and predictability of rates. Smith *et al.*, BP-16-E-JP08-01, at 11. In addition, because neither the customer groups nor their transmission usage will be the same in the BP-16 rate period as in the BP-14 rate period, correction of the error would result in generational inequity. *Id.* In addition, BPA has not explained why a \$12 million shift in costs is not large enough to require a change in segmentation, yet a similar shift with respect to the error is too large to leave uncorrected. *Id.* at 14-15. Finally, JP08 argues that because BPA now uses seven years of historical data to determine O&M costs rather than three, if BPA corrects the

BP-14 error it should use seven years of data to calculate the correct allocators instead of the three years it has proposed. JP08 Br., BP-16-B-JP08-01, at 16-18.

Powerex also argues that correction of the error would be illegal retroactive ratemaking. Powerex Br., BP-16-B-PX-01, at 22. Powerex adds that correction of the error would not reflect “customer class fairness” because the Utility Delivery and DSI Delivery segments would not be reallocated any costs, and that the error should be left as is in the interest of rate finality. Powerex Br., BP-16-B-PX-01, at 22-24. Finally, Powerex suggests that instead of allocating additional costs to certain segments to correct for the error, BPA should use transmission financial reserves. *Id.* at 24-25.

Snohomish argues that BPA should correct the error because the error violated principles of cost causation: certain transmission customers paid for O&M costs of facilities that did not benefit them. Snohomish Br., BP-16-B-SN-01, at 5. Snohomish argues that correction of the error would not be retroactive ratemaking and that the error warrants an equitable remedy. *Id.* Snohomish argues that BPA can correct past bills and therefore avoid the need to make a rate adjustment. Snohomish Br. Ex., BP-16-R-SN-01, at 3. In addition, Snohomish argues, if BPA does not correct past bills BPA should use reserves to compensate customers whose rates increased because of the error. *Id.* at 4.

WPAG argues that BPA should not correct errors from past rate cases until it adopts a policy that sets forth the criteria it will use to determine when to correct errors and when to leave them uncorrected. WPAG Br., BP-16-B-WG-01, at 26-27.

BPA Staff’s Position

Staff states that the over-allocation of \$9 million to the Network segment and the under-allocation of \$6 million to the Southern Intertie segment are too large to leave uncorrected. Fredrickson *et al.*, BP-16-E-BPA-14, at 15. Because almost all of BPA’s customers in the BP-16 rate period will be the same as the customers in the BP-14 rate period, fixing the error will result in little generational inequity. Fredrickson *et al.*, BP-16-E-BPA-26, at 10. Moreover, because the error did not reduce the costs allocated to the Utility Delivery and DSI Delivery segments in the BP-14 rate case, these segments should not be allocated any costs of correcting the error. *Id.* at 3-15. Finally, a three-year historical period for O&M costs should be used to fix the error because that was the historical period used to establish O&M costs in the BP-14 rate case. *Id.* at 11.

Evaluation of Positions

Rate stability and finality are among the most significant ratemaking principles. It is critical that, in order to plan their business affairs, parties know that established rates will not be revisited except under the most extraordinary circumstances. As JP08 noted, both the Administrator and the Commission approved the BP-14 rates. Smith *et al.*, BP-16-E-JP08-01, at 7-8. Correction of the BP-14 error would be the first time that, on its own initiative, BPA has revisited rates in one rate case to correct for a ratemaking error or decision it made in a prior rate case. Rates should not be revisited lightly, and this is not the case in which to do so.

Staff correctly notes that correction of a mathematical error is not the same as correction for deviations from forecasts, which are an inevitable and normal part of ratemaking. Fredrickson *et al.*, BP-16-E-BPA-26, at 7. Yet the effects of those deviations can be just as large as or even significantly larger than the effects of an error. For example, Staff did not contest JP07’s testimony that, from FY 2009 through FY 2014, BPA over-forecast net interest expense for transmission by an average of \$34.4 million per year. *See Deen et al.*, BP-16-E-JP07-01, at 12; Lennox *et al.*, BP-16-E-BPA-25, at 2. Although Staff continually works to refine and improve its forecasting process, Staff correctly rejected arguments to reduce net interest expense in this rate case because of past forecast errors. *Id.* at 4. Ratemaking is an intricate and complicated endeavor, and rates will never be set perfectly.

Staff argues that, because almost all of BPA’s customers in the BP-16 rate period will be the same as the customers in the BP-14 rate period, fixing the error will result in little generational inequity. Fredrickson *et al.*, BP-16-E-BPA-26, at 10. As the parties note, however, the customer mix will not be identical in both rate periods, and transmission usage by customer will differ, so the effects of the error cannot be corrected precisely. Smith *et al.*, BP-16-E-JP08-01, at 11; Opatrny, BP-16-E-PX-01, at 30-31. To the extent that the correction affects a new customer or one that has significantly changed its usage, correction could compound the error.

As the parties pointed out, Staff has not explained why this particular error is too large to leave uncorrected. The amount at issue is less than the cost of facilities Staff proposed to grandfather into the Network when Staff changed its segmentation policy in the Initial Proposal. Yet Staff defended the grandfathering on the ground that, if the facilities were removed from the Network, the revenue requirement “would change very little.” Tenney *et al.*, BP-16-E-BPA-16, at 32. If that is true, the Network revenue requirement was changed very little by this error, which therefore is not too large to leave uncorrected.

Snohomish argues that the revenue requirement impact of the error is not comparable to the impact of grandfathering of non-Network facilities, because grandfathering is a policy decision made after BPA accurately calculated rates according to its methodology. Snohomish Br. Ex., BP-16-R-SN-01, at 3. However, the proposal to revisit the BP-14 rates also raises a significant policy issue—the importance of rate finality. Moreover, Staff acknowledged that under a strict application of the segmentation methodology in the Initial Proposal, some of the facilities in the Network segment might be reassigned to another segment. Tenney *et al.*, BP-16-E-BPA-16, at 32. Therefore, the two issues are comparable in that in both cases the methodology was not the only consideration.

However, Snohomish is referring to cases in which the bills did not accurately reflect the rates that were in effect at the time. Therefore, no rate adjustment was necessary to correct the bills, as the correction simply ensured that the customer was charged the rate in effect. Bills issued under the BP-14 rates did accurately reflect the rates in effect at the time, since the rates included the error. Adjustment of the bills from the BP-14 rate period would mean an adjustment of the rates, and it is appropriate to decide whether to make that adjustment in a rate case.

Snohomish argues that BPA should use reserves to compensate the customers whose rates were higher because of the error. *Id.* at 4. BPA is already using \$15 million per year in reserves toward capital investments during the BP-16 rate period. As discussed at length in sections 4.2.2.1 and 4.2.2.2, the use of reserves raises significant policy issues and is best avoided on an ad hoc basis. BPA has committed to discuss the use of reserves and credit rating issues after the rate case. It is not prudent to use additional reserves until BPA works with the region to develop its financial reserves policy.

Finally, given the decision, the question of retroactive ratemaking is moot. Nevertheless, it should be noted that the prohibition of retroactive ratemaking does not apply to BPA. *Cent. Elec. Power Coop., Inc. v. Southeastern Power Admin.*, 338 F.3d 333, 337-38 (4th Cir. 2003). Because no re-allocation is being made, it is not necessary to explore this issue further at this time.

Decision

No re-allocation of costs will be made to correct for the misallocation of costs in the BP-14 rate case.

4.3.2 Cost Allocation for BPA’s Reliability Activities

Issue 4.3.2.1

Whether BPA should directly assign the projected costs of reliability compliance activities it performs under agreements it has with certain customers.

Parties’ Positions

JP05 argues that BPA should directly assign its projected costs of performing reliability compliance activities for certain customers related to the customer’s transmission facilities. JP05 Br., BP-16-B-JP05-01, at 1-2. JP05 argues in the alternative that since virtually all of the customers for which BPA performs these activities are BPA preference customers, the costs should be assigned to BPA’s power rates. *Id.* Similarly, JP04 argues that BPA is subsidizing certain preference customers’ costs of compliance with NERC/WECC requirements. JP04 Br. Ex., BP-16-R-JP04-01, at 3.

WPAG argues that JP05 has failed to identify any additional costs BPA incurs because it performs the activities. WPAG Br., BP-16-B-WG-01, at 24. Further, WPAG argues, because all customers benefit from the activities, JP05’s proposal “is at odds with the widely accepted cost causation principle that costs follow benefits.” *Id.* at 25.

BPA Staff’s Position

Staff opposes JP05’s recommendation. Tenney *et al.*, BP-16-E-BPA-28, at 5-7. Staff states that all customers benefit from these reliability-related activities. *Id.* Depending on the type of

contract BPA has with the customer, BPA either (1) does not incur additional costs, or (2) incurs some costs in documenting compliance activities, but also saves costs because performing the activities simplifies BPA's compliance responsibilities. *Id.*

Evaluation of Positions

JP05 argues that BPA should directly assign any costs of BPA's actions under its reliability-related agreements to the customers that are parties to the agreements because those actions benefit only those customers. JP05 Br., BP-16-B-JP05-01, at 5. BPA's agreements with these customers fall into two primary categories: (1) delegation agreements, under which BPA is responsible for compliance with certain standards that apply to the customer as a load-serving entity and distribution provider; and (2) transmission operator agreements, under which BPA has agreed to register with NERC as the transmission operator for certain customers' facilities and to assume legal responsibility for complying with the reliability standards that apply to transmission operators. Tenney *et al.*, BP-16-E-BPA-28, at 1.

Under the delegation agreements, BPA must: (1) maintain load-resource balance; (2) ensure that customers' facilities that interconnect to BPA's transmission system do not harm the reliability of the FCRTS; and (3) analyze the effectiveness of BPA's under-frequency load shedding (UFLS) program. *Id.* at 3-4. Further, BPA must respond to customers' requests for information in advance of a compliance audit. *Id.* at 4. JP05 states that the customers, not BPA, are obligated to perform the compliance activities for their facilities. JP05 Br., BP-16-B-JP05-01, at 5. However, no party rebuts Staff's testimony that NERC reliability standards require BPA to maintain load-resource balance and that BPA would have to perform this activity even in the absence of the delegation agreements. Tenney *et al.*, BP-16-E-BPA-28, at 3. Because BPA must already maintain load-resource balance, BPA incurs no additional costs because of the reliability-related agreements.

Similarly, no party rebuts Staff's testimony that, under BPA's Open Access Transmission Tariff, BPA must ensure that customers' facilities that interconnect to the FCRTS do not harm the transmission system and that, under NERC reliability standards, BPA must analyze the effectiveness of its UFLS program. *Id.* at 3-4. These responsibilities would exist even without the reliability-related contracts and thus result in no additional costs.

Finally, no party offers evidence to contradict Staff's testimony that BPA is already required to respond to customers' requests for information in advance of a compliance audit. *Id.* at 4. Again, the delegation agreements impose no additional obligations or costs. BPA entered into the agreements to memorialize responsibility for activities it has historically performed for its customers. *Id.* at 4-5. Therefore, it is incorrect that BPA is subsidizing customers' compliance with NERC reliability standards, and the existence of the agreements provides no reason to directly assign the costs.

BPA does incur costs under the transmission operator agreements. However, these agreements enhance the reliability of the transmission system and therefore benefit all customers. *Id.* at 5-6. For example, by acting as the customer's transmission operator, BPA can establish service more quickly after an outage, establish system operating limits on the customer's transmission system

to ensure that the customer's facilities are operated within acceptable reliability criteria, and gain more control over planned outages on the customer's facilities. *Id.* JP05 acknowledges that "the interconnected electrical system benefits from any operational efficiency and reliability compliance that may result from each individual utility's performance of its reliability obligations[,] but argues "[t]hat does not, however, provide any basis or rationale for BPA's ratepayers to subsidize compliance activities for any other utility." JP05 Br., BP-16-B-JP05-01, at 5. To the contrary: the benefits to the system as a whole provide a compelling reason to include the costs in general transmission rates. Tenney *et al.*, BP-16-E-BPA-28, at 7. BPA would have to perform some of the activities in any case; for example, BPA must have a NERC-qualified dispatcher to be the transmission operator for a customer or to operate its own system; and BPA saves costs by not having to coordinate with new transmission operators. *Id.* In sum, the transmission operator agreements are more akin to reliability tools for BPA's system than they are to agreements benefitting particular customers.

Citing testimony from the BP-14 rate case, JP05 argues that Staff has not presented any evidence that the costs associated with delegation and transmission operator agreements are minimal. JP05 Br., BP-16-B-JP05-01, at 8-9. However, BPA addressed this issue in the BP-14 Record of Decision:

Staff acknowledged that it does not track the costs individually, but it evaluated the actions it takes to comply with the standards addressed in the agreements and excluded the costs of activities that it would perform anyway for its own compliance obligations. Staff concluded that the costs attributable specifically to these agreements relate to staff time and administrative expense. Bogdon *et al.*, BP-14-E-BPA-43, at 24-25. Under the agreements, BPA does not perform operations and maintenance work that involves a physical presence out in the field, and its actions generally involve simple certifications of compliance, cooperation, and coordination with other transmission entities and actions that BPA would perform for the FCRTS regardless of the agreements. *Id.* at 19-21. Given the evidence regarding the nature and extent of the tasks that BPA is performing under the agreements, it is reasonable to conclude that the costs are limited.

BP-14 Power and Transmission Rate Proceeding, Administrator's Final Record of Decision, BP-14-A-03, at 184 (July 2013). JP05 has not presented any evidence that changes this conclusion. JP05's argument that "BPA is silent as to the level of any cost it incurs of documenting the compliance of the *customers* under the delegation agreements or transmission operator agreements" is unpersuasive. JP05 Br., BP-16-B-JP05-01, at 9-10 (emphasis in original). In the case of transmission operator agreements, the customer has no compliance responsibilities to document because BPA has assumed legal responsibility for complying with the reliability standards that apply to the transmission operator. In the case of delegation agreements, the above statement from the BP-14 Record of Decision still holds true, and it is still reasonable to conclude that the costs are limited.

JP04 and JP05 also express concern that BPA may be liable for monetary penalties for actions taken under the agreements. JP04 Br. Ex., BP-16-R-JP04-01, at 3; JP05 Br., BP-16-B-JP05-01, at 13. JP05 argues that BPA may receive a much larger penalty than the customer because of BPA's greater ability to pay a large penalty. JP05 Br., BP-16-B-JP05-01, at 13. However, BPA has not paid any penalties under the agreements and expects this record to continue. Tenney *et al.*, BP-16-E-BPA-28, at 2. Indeed, a primary purpose of the agreements is to avoid violations and potential penalties through improvements to reliability.

Finally, JP05 argues that if BPA does not directly assign the costs of the agreements to the customers, then it should assign such costs to power rates because virtually all of the customers with such agreements are BPA preference customers that purchase Federal power. JP05 Br., BP-16-B-JP05-01, at 1-2. However, JP05 has not established a connection between these agreements and the sale of Federal power. To the contrary, the agreements are related to the reliability of the transmission system, not the sale of Federal power. Tenney *et al.*, BP-16-E-BPA-28, at 7. Transmission costs are always assigned to transmission rates; the identity of the purchaser is immaterial. These costs are no different.

Decision

BPA will not directly assign the costs of reliability compliance activities BPA performs on behalf of individual customers.

4.3.3 Southern Intertie Hourly Non-Firm Rate

The rate for hourly non-firm service on the Southern Intertie is set by first dividing the annual Southern Intertie long-term firm rate by the average number of hours per year in the rate period (8,772 hours for the BP-16 rate period). Next, that result is multiplied by 24/16 (24 hours per day divided by the 16 heavy load hours). This step ensures that customers that reserve transmission during all 16 heavy load hours, when loads are typically the highest, pay the same amount as long-term firm customers that have the right to schedule transmission 24 hours a day. Linn *et al.*, BP-16-E-BPA-31, at 1-2. That result is multiplied by 7/5 (7 days a week divided by 5 weekdays). This step ensures that customers that reserve transmission for five weekdays, again when loads are typically the highest, pay the same amount as long-term firm customers that have the right to schedule every day of the week. *Id.*; *see also* Transmission Rates Study and Documentation, BP-16-FS-BPA-07, § 5.1. The practical result of this methodology is that a customer that reserves 1 MW for 80 hours of hourly non-firm transmission service a week (16 hours a day multiplied by five days) pays the same amount as a long-term firm customer that buys 1 MW. Linn *et al.*, BP-16-E-BPA-31, at 1-2. Staff proposes to retain this methodology for FY 2016–2017, resulting in a proposed rate of 3.59 mills/kWh.

JP06 opposes calculating the hourly non-firm rate based on 80 hours a week and instead proposes that BPA base the rate on actual reservations of hourly non-firm service in FY 2012–2014. JP06 Br., BP-16-B-JP06-01, at 10-12. JP06 calculates the actual use of hourly non-firm service to be approximately 23 hours per customer per week. *Id.* Based on that calculation, JP06 proposes setting the hourly non-firm rate so that a customer that reserves

1 MW for 23 hours per week of hourly non-firm transmission service pays the same amount as a long-term firm customer that buys 1 MW. JP06's proposal results in a rate of 12.97 mills/kWh. *Id.*

Issue 4.3.3.1

Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week is equitable.

Parties' Positions

JP06 argues that basing the hourly non-firm rate on 80 hours a week does not equitably allocate the costs between firm and non-firm transmission service on the Southern Intertie. *Id.* at 10. JP06 also states that Staff's use of 80 hours a week "is not based on any actual data regarding reservations of IS HNF [Southern Intertie hourly non-firm] service." *Id.* JP06 argues that actual usage of Southern Intertie non-firm service from FY 2012 to FY 2014 was 23 hours per week, and that the rate should be based on this figure. *Id.* at 10-12.

BPA Staff's Position

Staff states that its proposal equitably distributes costs between firm and non-firm service while still maintaining an incentive to reserve long-term firm service. Linn *et al.*, BP-16-E-BPA-31, at 3. Staff claims its "methodology is not based on the assumption that customers will actually purchase 16 hours of non-firm transmission service, five days a week (80 hours of transmission per week)." *Id.* Instead, Staff's method "creates an incentive to purchase long-term firm transmission by making it more expensive to purchase hourly service if a customer's demand exceeds 80 hours per week." *Id.*

Evaluation of Positions

JP06 states that Staff's proposal to base the hourly non-firm rate on 80 hours a week of reservations is inequitable because a customer that schedules 1 MW for 23 hours of non-firm service per week would pay \$86 per week for that service, whereas a long-term firm customer would pay \$298 to schedule 1 MW for that same 23 hours per week. JP06 Br., BP-16-B-JP06-01, at 11. JP06 contends that this result "is contrary to BPA's rate design framework that seeks to set rates that result in similar total weekly contributions to embedded cost recovery across all types of Southern Intertie transmission service." *Id.*

The example that JP06 provides is not persuasive. An hourly non-firm customer pays \$86 for service because it can use the Southern Intertie for only the 23 hours a week it has reserved, whereas a long-term firm customer has the right to schedule its Southern Intertie reservation for all 168 hours of the week. Linn *et al.*, BP-16-E-BPA-31, at 3. Long-term firm customers pay more because they can use the Southern Intertie more.

JP06's argument that Staff's proposal "is not based on any actual data regarding reservations of IS HNF service," JP06 Br., BP-16-B-JP06-01, at 10, is also misplaced. Staff's use of 80 hours a

week “is not an attempt to anticipate the number of hours that the average customer will use hourly non-firm transmission in a given week.” Linn *et al.*, BP-16-E-BPA-31, at 3. Rather, it is meant to provide an incentive to purchase long-term firm service and is a methodology commonly used by other transmission providers. *Id.*

JP06 states that its methodology is based on actual reservations of hourly non-firm transmission. JP06 Br., BP-16-B-JP06-01, at 25. However, the methodology does not reflect actual demand for hourly non-firm service because it accounts only for hours in which a customer can make an hourly non-firm reservation and overlooks those hours in which there is a lack of capacity. Linn *et al.*, BP-16-E-BPA-31, at 7. This limitation artificially lowers the number of hours to 23 and increases the rate. *Id.* Similarly, the methodology overlooks the fact that there are two separate paths on the Southern Intertie (the alternating-current (AC) path and the direct-current (DC) path). *Id.* If a customer makes one hourly non-firm reservation on the AC path and one reservation on the DC path in the same hour, these should count as two reservations: they are two hours of reservation under two separate paths. *Id.* However, JP06 counts this as only one reservation for one hour. *Id.* This method lowers the number of hours and increases the rate.

Furthermore, JP06’s methodology ignores the volume (MW) of hourly non-firm transmission reservations. *Id.* For example, a 1 MW hourly non-firm reservation and a 100 MW reservation both count as one hour of use, even though the latter reservation results in one hundred times more revenue than the former. *Id.*

Finally, JP06 argues that its proposal results in hourly non-firm rates similar to those of the Transmission Agency of Northern California (TANC), the Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP). JP06 Br., BP-16-B-JP06-01, at 12. Although the absolute levels of these transmission providers’ hourly non-firm rates are close to the rate in JP06’s proposal, their rates are meaningful only when compared to their long-term firm rates. On TANC’s system, a customer would have to reserve 60 hours of non-firm transmission to pay the same as the long-term firm rate; on SMUD’s system, 104 hours; and on LADWP’s system, between 80 and 168 hours. Linn *et al.*, BP-16-E-BPA-31, at 6. These figures are much more in line with BPA’s methodology than with JP06’s proposal.

Decision

Basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week is equitable.

Issue 4.3.3.2

Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie.

Parties' Positions

JP06 maintains that “the California Independent System Operator ... has designed its market in a manner that grants awards for deliveries into its markets without regard to the seller’s transmission priority under BPA’s Open Access Transmission Tariff ... framework.” JP06 Br., BP-16-B-JP06-01, at 1-2. According to JP06, this market design leads to a “disincentive for future LTF [long-term firm] subscriptions and renewals that, if left unchecked, could ultimately jeopardize BPA’s cost recovery for existing and future expansion projects.” *Id.* at 2. JP17 agrees that “the current rate fails to meet its intended objective to incentivize the purchase of long-term service.” JP17 Br., BP-16-B-JP17-01, at 4.

BPA Staff's Position

Staff states that its methodology creates an adequate incentive for customers to reserve long-term firm service. Linn *et al.*, BP-16-E-BPA-31, at 4. The Southern Intertie remains fully subscribed in the southbound direction, and there is a queue of customers waiting for long-term firm service. *Id.*

Evaluation of Positions

JP06 states that the rate disparity between long-term firm and non-firm service makes it “attractive for a shipper to rely on IS HNF [hourly non-firm] service, purchased only in the specific hours in which service is desired, rather than committing to paying for IS LTF [long-term firm] service for every hour of the year in order to access the California ISO market.” JP06 Br., BP-16-B-JP06-01, at 11. As JP06 acknowledges, however, the California ISO adopted its current market design in 2009. *Id.* at 9. Yet the Southern Intertie remains fully subscribed in the southbound direction, and BPA has a long queue of customers waiting for capacity. Linn *et al.*, BP-16-E-BPA-31, at 4. Nonetheless, JP06 argues that the disincentive to purchase long-term firm service “has materialized and accelerated in the past two years as the California ISO has more actively publicized that its market process ensures that those participants receiving California ISO awards will be able to obtain transmission service on external providers’ systems.” JP06 Br., BP-16-B-JP06-01, at 9-10.

In fact, however, participants that rely on hourly non-firm transmission often cannot obtain service on BPA’s system during times of high Intertie demand because the capacity is being scheduled by customers with long-term service. From FY 2012 to FY 2014 there were a significant number of hours where customers attempted to obtain hourly non-firm service on the Southern Intertie, but it was unavailable. Linn *et al.*, BP-16-E-BPA-31, at 4. Furthermore, JP06’s arguments are focused solely on the California ISO markets. Its proposal does not recognize any value for other uses of its long-term transmission, such as bilateral sales. *Id.* at 4-5. The robust sales and long queue for Southern Intertie service demonstrate that the

capacity has significant value. Although JP06 has asserted that BPA should expect to lose revenues in the future, it has presented no evidence that this is likely to be the case.

JP06 also notes that the California ISO has designed its market in a manner that grants awards for deliveries without regard to the seller's transmission priority under BPA's Open Access Transmission Tariff. JP06 Br., BP-16-B-JP06-01, at 1-2. JP06 states that the result is that power bid by transmission customers that reserve hourly non-firm service flows ahead of power bid by customers that have reserved long-term firm transmission from BPA. *Id.* at 9. Thus, JP06 concludes, "the superior service that LTF [long-term firm] is supposed to enjoy as a matter of right under BPA's OATT is overridden by the California ISO market design." *Id.*

In fact, the OATT and the California ISO market rules govern separate transactions. The OATT concerns the transmission provider's sale of transmission capacity. It does not govern power purchasers' decisions. The OATT does not apply to downstream actions by other entities, particularly entities that themselves do not operate under the *pro forma* OATT. BPA's OATT does not prevent an organized market (or any purchaser, for that matter) from selecting bids that utilize non-firm transmission service. Instead, a purchaser can select any bid for power it wants without regard to transmission priority.

Therefore, it is not appropriate to adopt JP06's proposed methodology. Nevertheless, there may be a need for focused exploration of JP06's and JP17's concerns. JP06 is correct that customers with current long-term firm reservations have no obligation to renew, that parties in the queue for long-term firm service on the Southern Intertie are not generally under any binding obligation to commit to service, and that over half of long-term firm reservations will expire by 2020. JP06 Br., BP-16-B-JP06-01, at 3, 17. JP06 also states that loss of long-term firm sales on the Southern Intertie may reduce utilization of the Intertie, as well as "simply make it impossible to recover the embedded costs of the Southern Intertie from the users of those facilities." *Id.* at 18.

As explained above, none of these events has occurred, even though the same conditions have existed since 2009. However, BPA does not dismiss JP06's witnesses' "real-world experience coping with the impact of the California ISO market design decisions." *Id.* at 2. After the Final Record of Decision is issued, BPA will hold a series of workshops in which all interested stakeholders will have an opportunity to address the issues raised by JP06, JP17, and any other interested parties, as well as potential rates and non-rates options to address the issues if necessary. Meanwhile BPA will continue to monitor Southern Intertie sales to help determine whether any action is necessary. This decision does not foreclose the possibility of a separate rate proceeding prior to the BP-18 rate case if it is concluded that action is needed and a rates option is identified.

Decision

Basing the Southern Intertie hourly non-firm hourly rate on 80 hours of reservations a week currently creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie. BPA will hold workshops after the conclusion of the rate case to explore this issue further.

Issue 4.3.3.3

Whether BPA's ability to discount the hourly non-firm rate mitigates concerns regarding the stability of an hourly non-firm rate based on actual usage.

Parties' Positions

JP06 states that it recognizes Staff's concern that basing the hourly non-firm rate on historical usage could create upward pressure on the rate, as rate increases lead to declines in usage and consequent additional rate increases. JP06 Br., BP-16-B-JP06-01, at 24. JP06 argues, however, that BPA's ability to discount the hourly non-firm rate should mitigate any concerns about rate instability. *Id.*

JP17 states that JP06's proposal to base the hourly non-firm rate on recent years' usage of 23 hours is a clear step toward more accuracy, and there will be no more reason to modify this number in future rate cases than there has been to modify BPA's use of 80 hours. JP17 Br., BP-16-B-JP17-01, at 3-4.

BPA Staff's Position

Staff argues that “[i]f BPA were to adopt JP06's proposal to more than triple hourly non-firm rates, the use of hourly non-firm transmission likely would drop in the next rate period.” Linn *et al.*, BP-16-E-BPA-31, at 7. Since the rate is based on historical usage, that would result in even higher rates during the next rate period, which would result in even less usage and even higher rates. *Id.* Staff also states that hourly non-firm transmission is not always available, yet JP06's methodology is based only on what customers were able to reserve. *Id.* Therefore, JP06's calculation of hours per week is skewed towards a lower result, based as much on available hours as true demand. *Id.*

Evaluation of Positions

Basing the hourly non-firm rate on actual usage would raise significant concerns regarding the stability of the rate. JP06's proposal would more than triple the non-firm rate in the BP-16 rate period, which would likely significantly reduce the use of hourly non-firm service. *Id.* at 7. If BPA ignored this reduction in use and kept the rate the same, the rate would no longer be based on usage and the rationale for the rate would no longer exist. Therefore, JP06's proposal would likely lead to higher rates in future rate periods. *Id.*

JP06 states that BPA can discount the hourly non-firm rate to ensure rate stability. JP06 Br., BP-16-B-JP06-01, at 24. Thus, JP06 suggests that BPA can mitigate its concerns by adopting JP06's proposal and then effectively reversing it. Rather than addressing rate stability from rate period to rate period by discounting the rate, the rate should be based on a more durable methodology that does not need to be undone to preserve rate stability.

JP17 argues that there would be no more reason to re-evaluate JP06's figure for actual usage every rate period than there has been to re-evaluate BPA's use of 80 hours, which according to JP17 is based on “anticipated use” of non-firm hourly service. JP17 Br., BP-16-B-JP17-01, at 3.

The existing rate, however, is not based on anticipated usage. Linn *et al.*, BP-16-E-BPA-31, at 3. Instead, the existing methodology is intended to create an incentive to purchase long-term firm service by making it more expensive to purchase hourly non-firm service if a customer's demand exceeds 80 hours per week. *Id.* Because the methodology is not based on changing historical data, there is no need to revisit it each rate period. A rate based on actual usage, however, could quickly become inaccurate unless it is regularly revisited.

Decision

BPA's ability to discount the hourly non-firm rate does not mitigate concerns regarding the stability of an hourly non-firm rate based on actual usage. Staff's proposal will be adopted.

4.3.4 Oversupply Rate

The OS-16 rate recovers costs attributable to BPA's Oversupply Management Protocol (OMP). Staff's proposal is the same as the OS-14 rate that was adopted pursuant to the OS-14 rate proceeding, except for three limited revisions: (1) removing the exemption from cost allocation that applied to generators that did not submit displacement costs in 2012; (2) deleting a billing provision that was specific to the recovery of costs from 2012 and no longer applies; and (3) updating the Modified Tier 1 Cost Allocators (TOCAs) to reflect the forecast of FY 2016 and FY 2017 TOCAs. Bliven and Fredrickson, BP-16-E-BPA-11, at 3. In addition, Staff proposes to recover the administrative costs of OMP incurred from FY 2012 through FY 2014, plus the forecast OMP administrative costs for FY 2015–2017, by including these costs in the transmission revenue requirement and allocating the costs across all transmission segments. *Id.* at 4-5. The administrative costs consist of the fee of an independent evaluator that collects the costs of displacement submitted by generators, audits the costs, and constructs a least-cost displacement cost curve that BPA uses to determine which generators should be curtailed during oversupply events. *Id.* at 4.

In briefs, no party raised any specific issues with Staff's proposal to recover the administrative costs. Therefore, Staff's proposal will be adopted.

The Oversupply Management Protocol

BPA markets power from the Federal hydro projects operated by the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation in the Pacific Northwest. During spring runoff, water flows can be higher than needed to meet regional electric load and exports. In addition, water storage and hydro generating capacity at Federal dams are limited. Therefore, excess water sometimes must be spilled over the dams' spillways (channels to permit the release of excess water). However, high levels of spill can create excessive amounts of total dissolved gas (TDG) in the water, which can lead to gas bubble trauma that threatens the health of the ecosystem and aquatic life, including Endangered Species Act-listed fish. Bonneville Power Administration, BPA's Interim Environmental Redispach and Negative Pricing Policies: Administrator's Final Record of Decision, at 5-11 (May 2011).

The states of Washington and Oregon have authority under the Clean Water Act to set TDG levels. BPA must adhere to both the Clean Water Act and the Endangered Species Act. Therefore, the Corps and the Bureau of Reclamation plan FCRPS operations to comply with applicable state and tribal water quality standards and minimize excess TDG to the extent practicable by limiting the amount of excess spill. For the last several years, spill and water quality constraints were adopted by court order in litigation mandating that spill operations be conducted as set forth in annual spill orders and Fish Operation Plans. *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 839 F. Supp. 2d 1117 (D. Or. 2011).

To avoid excess spill, historically BPA offered to displace non-Federal generation with low-cost or free Federal hydropower. In recent years, however, BPA has integrated 4,500 megawatts of wind generation into the Federal Columbia River Transmission System (FCRTS). Some wind generators receive Federal production tax credits (PTCs) and state renewable energy credits (RECs). PTCs are credits against wind generators' Federal income taxes, and RECs are credits that purchasers of wind generation can use to satisfy their obligations under state law to ensure that a certain percentage of the electricity they sell is produced by renewable resources. Because the generators are granted credits based on the amount of energy they generate, wind generators have no incentive to accept free power to curtail their production and allow BPA to mitigate excess spill.

In March 2011 BPA established an interim environmental redispatch policy under which BPA displaced generators that did not accept offers of free power during periods of high water. BPA substituted free Federal hydropower for the displaced generation. Wind generators and other parties filed a complaint with the Commission under section 211A of the Federal Power Act. That Act authorizes the Commission to order unregulated transmitting utilities (including BPA) to offer transmission service on terms and conditions that are comparable to the terms and conditions under which they provide transmission service to themselves and that are not unduly discriminatory or preferential. The complainants argued that BPA's policy discriminated against wind projects.

The Commission held that BPA's environmental redispatch policy violated section 211A and directed BPA to file tariff revisions within 90 days that addressed the comparability concerns raised in the proceeding in a manner that provides comparable transmission service that is not unduly discriminatory or preferential. BPA responded by adopting the Oversupply Management Protocol, under which BPA compensates displaced generators for certain costs related to displacement, including (1) PTCs; (2) RECs unbundled (sold separately) from the sale of energy; and (3) for contracts executed prior to March 6, 2012, certain losses under bundled contracts (sales of renewable energy credits and energy together) because of the generators' failure to deliver wind power.

On March 6, 2012, BPA filed the OMP with the Commission. In the filing, BPA informed the Commission that it intended to make an initial proposal in the oversupply rate case to allocate 50 percent of the costs of oversupply to power customers and 50 percent to wind generators.

On December 20, 2012, the Commission issued an order conditionally accepting the OMP on an interim basis, subject to BPA's filing a new cost allocation proposal within 90 days. BPA requested rehearing on this issue and also requested a stay of the compliance filing deadline to allow BPA to complete its rate case. The Commission denied rehearing but granted BPA's request for a stay, extending the deadline for filing the cost allocation methodology to a date 30 days after BPA submits its final oversupply rate decision to the Commission.

BPA's original OMP expired on March 30, 2013. Therefore, on March 1, 2013, BPA filed an updated protocol to be effective from March 31, 2013, through September 30, 2015. On October 16, 2014, the Commission issued a final order approving BPA's OMP filing. *Iberdrola Renewables, Inc., v. Bonneville Power Admin.*, 149 FERC ¶ 61,044 (2014).

The OS-14 Rate Proceeding

On November 8, 2012, BPA began the OS-14 rate proceeding to establish a rate to recover the displacement costs BPA incurred under the OMP. BPA originally proposed a cost allocation methodology that allocated 50 percent of the costs to power customers and 50 percent of the costs to wind generators. The Commission rejected that proposal in its order conditionally approving the OMP. On March 27, 2014, the Administrator issued a Final ROD in the OS-14 rate case establishing a rate that allocates costs to generators in BPA's balancing authority area based on their transmission schedules during oversupply event hours. The Administrator concluded that this allocation

best aligns with principles of cost causation because the scheduling of generation during oversupply events, as measured by transmission schedules, causes the need to displace generation and hence oversupply costs, and because the need to displace extends only to generators within BPA's balancing authority area.

OS-14 Oversupply Rate Proceeding, Administrator's Record of Decision, OS-14-A-02, at 19 (March 2014) (OS-14 ROD). On October 16, 2014, the Commission issued two final orders approving BPA's OS-14 rate, one approving the OS-14 rate under section 211A of the Federal Power Act and one approving the OS-14 rate under the Northwest Power Act. *Iberdrola Renewables, Inc., v. Bonneville Power Admin.*, 149 FERC ¶ 61,044 (2014); *Bonneville Power Admin.*, 149 FERC ¶ 61,043 (2014). Staff proposes to adopt the same cost allocation for the OS-16 rate.

Issue 4.3.4.1

Whether Staff's cost allocation proposal should be adopted.

Parties' Positions

Iberdrola argues that oversupply costs are caused by BPA's fish and wildlife obligations and inability to sell excess power and therefore should be allocated to power rates. Iberdrola Br., BP-16-B-IR-01, at 7-9. Iberdrola argues that the need to pay wind generators to displace is not

the cause of oversupply costs. *Id.* at 8. In addition, Iberdrola argues that oversupply costs are also a result of BPA’s inability to sell excess power on the market for a price other than a negative price. *Id.*

JP01 also argues that oversupply costs should be allocated to power rates because they are caused by BPA’s fish and wildlife obligations and inability to sell excess power. JP01 Br., BP-16-B-JP01-01, at 9. JP01 denies that transmission usage causes oversupply costs, arguing that BPA would still experience the same oversupply problems if non-Federal generation did not use BPA’s transmission. *Id.* at 6. JP01 also argues that BPA’s rationale is inconsistent with the Commission’s conclusion, as the Commission concluded that oversupply was caused by insufficient transmission capacity. *Id.* at 7-8.

JP09, WPAG, ICNU, and M-S-R all support Staff’s proposal. JP09, ICNU, and WPAG argue that JP01 and Iberdrola make the same arguments that were raised and rejected by BPA in the OS-14 rate proceeding and that they should be rejected again. JP09 Br., BP-16-B-JP09-01, at 8; ICNU Br., BP-16-B-IN-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 27-28. JP09 and ICNU additionally argue that there has been no change in facts or circumstances that would justify a different cost allocation. JP09 Br., BP-16-B-JP09-01, at 8-9; ICNU Br., BP-16-B-IN-01, at 10-11. M-S-R argues that it would be inefficient to adopt a new proposal given “the pending challenges and market dynamics.” M-S-R Br., BP-16-B-MS-01, at 24.

JP04 argues that no evidence supports the Draft ROD’s assertion that BPA fulfills its environmental obligation by displacing generation in its balancing authority area. JP04 Br. Ex., BP-16-R-JP04-01, at 7. JP04 challenges BPA’s decision to assign revenues from selling excess power at a positive price to power rates while assigning costs of disposing of power at a negative price to transmission rates. *Id.* at 8. JP04 states that BPA is charging power costs to transmission customers. *Id.*

BPA Staff’s Position

Staff proposes the same cost allocation methodology established in the OS-14 rate case. Bliven and Fredrickson, BP-16-E-BPA-11, at 2. Staff reiterates the position adopted in the OS-14 ROD that the scheduling of generation in BPA’s balancing authority area, as measured by transmission schedules, causes the need to displace generation and hence the incurrence of oversupply costs. *Id.* at 1-3.

Evaluation of Positions

Iberdrola’s and JP01’s argument that oversupply costs are caused solely by BPA’s fish and wildlife obligations and inability to sell excess power has already been considered and rejected in the OS-14 ROD. As BPA explained:

These arguments overlook the fact that BPA incurred no oversupply costs before the interconnection and integration of wind generation. Because of the interconnection of wind generation in BPA’s balancing authority area, and

because these generators require compensation for displacement, BPA now incurs oversupply costs.

OS-14 ROD at 21. Staff reiterated this position in testimony, and neither Iberdrola nor JP01 has presented any new arguments that would compel a different conclusion. Bliven and Fredrickson, BP-16-E-BPA-24, at 1-3.

JP01's argument that non-Federal generation does not cause oversupply costs, because BPA would still experience the same oversupply problems if non-Federal generation used non-Federal transmission, was also raised and rejected in the OS-14 ROD. OS-14 ROD at 21-22. As explained in that ROD, BPA satisfies its environmental responsibilities when it displaces the generation in its balancing authority area over which BPA has operational control. *Id.* Because BPA does not have operational control over generation outside its balancing authority area, BPA has no obligation to displace those generators and incur costs. *Id.* Thus, if non-Federal generation used non-Federal transmission, there would be no oversupply costs. Staff reiterated this position in its testimony in this case. Bliven and Fredrickson, BP-16-E-BPA-24, at 4. Again, JP01 has offered no reason for a different conclusion.

JP01 also argues that BPA's rationale is inconsistent with the Commission's rationale in approving BPA's OS-14 rate and that BPA cannot rely on the Commission's approval without explaining the inconsistency. JP01 Br., BP-16-B-JP01-01, at 7-8. Specifically, JP01 argues that the Commission found that oversupply costs are caused by the lack of transmission capacity, whereas BPA found that transmission capacity was not an issue. *Id.* This issue was raised in a request for rehearing of the Commission's order approving the OS-14 rate and in JP01's direct testimony. Holland *et al.*, BP-16-E-JP01-01, at 8-9. The Commission rejected the argument on rehearing:

We recognize that it is not a lack of transmission capacity that causes the need to displace generators, but rather a need to match generation being delivered over the system with load. Oversupply costs are nevertheless appropriately viewed as transmission costs because it is generation scheduled to be delivered over the system ... which is then displaced that creates the oversupply costs.

Iberdrola Renewables Inc. v. Bonneville Power Admin., 150 FERC ¶ 61,113, at P 19 n. 27 (2015). The Commission thus made clear that it did not base its conclusion on a transmission capacity problem. Moreover, the Commission, the agency statutorily charged with reviewing and approving BPA's rates, approved BPA's OS-14 rate, and it would defy reason for BPA to reject the Commission's approval based on one sentence in the Commission's order. Thus, JP01's argument has no basis.

JP04's argument regarding the scope of BPA's environmental obligations, JP04 Br. Ex., BP-16-R-JP04-01, at 7, is not a rate case issue. In any case, the scope of BPA's obligations is a legal issue, not an evidentiary issue. In addition, even before the interconnection of wind generation BPA followed this construct in oversupply situations, displacing all thermal generation in its balancing authority area with free power. OS-14 ROD at 19. Only after the interconnection of

wind generation did BPA incur a cost for displacing generation. *Id.* Thus, the interconnection of wind generation causes oversupply costs.

Decision

Staff's cost allocation proposal will be adopted.

Issue 4.3.4.2

Whether the allocation of oversupply costs to transmission rates complies with section 7(g) of the Northwest Power Act.

Parties' Positions

Iberdrola and JP01 argue that under section 7(g) of the Northwest Power Act, the costs of fish and wildlife measures and the inability to sell excess power must be allocated to power rates. Iberdrola Br., BP-16-B-IR-01, at 4-6; JP01 Br., BP-16-B-JP01-01, at 15-18. These parties also argue that it is unfair to allocate the benefits of the sale of surplus power to power rates but allocate the cost of a sale of power at a negative price through OMP to transmission rates. Iberdrola Br., BP-16-B-IR-01, at 5-6; JP01 Br., BP-16-B-JP01-01, at 16-17.

JP09 and WPAG argue that in the OS-14 rate proceeding BPA rejected parties' arguments that section 7(g) of the Northwest Power Act requires oversupply costs to be allocated to power rates. JP09 Br., BP-16-B-JP09-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 28-29. In addition, JP09 and WPAG argue that oversupply costs are transmission costs that are allocated to transmission rates through other provisions of the Northwest Power Act; therefore, section 7(g) does not apply. JP09 Br., BP-16-B-JP09-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 28-29.

BPA Staff's Position

This is a legal issue and was not addressed by Staff in testimony.

Evaluation of Positions

Iberdrola and JP01 raise the same argument challenging the allocation of costs to transmission customers under section 7(g) of the Northwest Power Act that was raised in the OS-14 rate proceeding. Section 7(g) of the Northwest Power Act provides as follows:

Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 839d

of this title, the cost of credits granted pursuant to section 839d of this title, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g) (2006) (emphasis added).

In the OS-14 ROD, the Administrator found that oversupply costs are attributable to the interconnection of wind generation in BPA's balancing authority area. OS-14 ROD at 27-28. Because interconnection is a transmission service, the Administrator found that oversupply costs were costs attendant to the transmission of power that are properly allocated under sections 9 and 10 of the Transmission System Act and section 7(a)(1) of the Northwest Power Act. *Id.* at 30. The first clause of section 7(g) of the Northwest Power Act makes clear that the section does not apply if costs are already allocated under other provisions of law. Therefore, section 7(g) does not require that the costs of oversupply be allocated to power rates.

In the OS-14 rate proceeding, parties also made the same argument that Iberdrola and JP01 make here regarding the allocation of the costs and benefits of the sale and inability to sell excess power. In rejecting that argument, BPA explained, “[s]econdary sales—the sale of additional power off-system after BPA has satisfied its contractual obligations for the sale of power—are purely a power function. The revenues from these sales are not created by the interconnection of generators or by any other transmission action.” OS-14 ROD at 32. Because oversupply costs are caused by the interconnection of wind generators, which is a transmission service, and secondary sales are a power function, there is no inequity in allocating secondary sales revenues to power and oversupply costs to transmission.

Decision

The allocation of oversupply costs to transmission rates complies with section 7(g) of the Northwest Power Act.

Issue 4.3.4.3

Whether the OS-16 rate equitably allocates costs between Federal and non-Federal users of the transmission system under section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

Parties' Positions

JP01 argues that, because oversupply costs are power costs, the equitable allocation standard of section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act prohibits the allocation of the costs to transmission rates. JP01 Br., BP-16-B-JP01-01, at 18-19.

JP09 and WPAG argue that oversupply costs are transmission costs and thus satisfy the equitable allocation standard. JP09 Br., BP-16-B-JP09-01, at 14-15; WPAG Br., BP-16-B-WG-01, at 30. JP09 and WPAG argue that BPA and the Commission have already concluded that the allocation of oversupply costs to transmission meets the equitable allocation standards and that there is no

reason to reach a different conclusion in this case. JP09 Br., BP-16-B-JP09-01, at 14-15; WPAG Br., BP-16-B-WG-01, at 30.

BPA Staff's Position

This is a legal issue and was not addressed by Staff in testimony.

Evaluation of Positions

Section 10 of the Transmission System Act provides, in part, that “[t]he recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system.” 16 U.S.C. § 838h (2006). This standard was reiterated in section 7(a)(2)(C) of the Northwest Power Act, under which the Commission approves BPA’s transmission rates upon a finding that such rates “equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.” § 839e(a)(2)(C) (2006). *See Cent. Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101, 1114-15 (9th Cir. 1984) (the equitable allocation requirement of section 7(a)(2)(C) of the Northwest Power Act “has its roots” in section 10 of the Transmission System Act). The Commission has interpreted section 7(a)(2)(C) to require a separate accounting of power and transmission costs so that the Commission can determine that “(1) transmission revenues are only used to repay transmission costs; (2) *costs assigned to transmission are only transmission related costs*; and (3) any deficiencies or surpluses in transmission revenues are being tracked and collected or credited to the appropriate customer class.” *U.S. Dep’t of Energy–Bonneville Power Admin.*, 25 FERC ¶ 61,140, at 61,375-76 (1983) (emphasis added).

JP01’s argument was raised and rejected in the OS-14 ROD, as JP09 and WPAG correctly point out. As the Administrator explained:

[Oversupply] costs are caused by BPA’s interconnection of wind generators and BPA’s management of the transmission system during oversupply conditions. Both interconnection and the exercise of operational control are actions attendant to the transmission of power. Therefore, assigning oversupply costs to transmission rates is consistent with the equitable allocation standard.

OS-14 ROD at 37. The Commission approved the OS-14 rate as meeting the equitable allocation standard under section 7(a)(2)(C) of the Northwest Power Act. *Bonneville Power Admin.*, 149 FERC ¶ 61,043, at P 24 (2014). For the reasons stated above, the allocation of oversupply costs meets the equitable allocation standards under section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

Decision

The OS-16 rate equitably allocates costs to Federal and non-Federal users of the transmission system and complies with section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

4.3.5 Elimination of the Montana Intertie Rate

The Montana Intertie is the 500-kV line that runs from Broadview substation on NorthWestern Energy's transmission system west to Townsend, and then west from Townsend on BPA's system to Garrison substation. The Montana Intertie (IM) rate is available to transmission customers taking Point-to-Point transmission service on the Eastern Intertie, which is the part of the Montana Intertie owned by BPA. The Eastern Intertie is the 500-kV line between Townsend and Garrison substation. BPA's Network begins at Garrison substation and extends west from there.

The westbound capacity of the Eastern Intertie is 1930 MW. BPA has sold 1730 MW of this capacity to the owners of the Colstrip coal plant. Of the remaining 200 MW, BPA has sold 16 MW. Elimination of the IM rate, as proposed by Renewable Northwest, would mean that BPA's share of Eastern Intertie costs would be included in Network rates. BPA's share of the costs equals the amount of remaining westbound capacity BPA sells divided by the total capacity sold. For example, if BPA sells 100 MW of the remaining capacity, the total sold would be 1830 MW. BPA's share of the costs would be 5.5 percent (100/1830).

Some parties framed their opposition to Renewable Northwest's proposal in terms of opposing roll-in of BPA's share of the costs of the Eastern Intertie into Network rates. In terms of ratemaking, "roll-in of the costs" and "elimination of the IM rate" are the same thing—inclusion of BPA's share of Eastern Intertie costs in Network rates.

Issue 4.3.5.1

Whether to eliminate the IM rate and charge Network rates for Point-to-Point service over the Eastern Intertie starting at Townsend.

Parties' Positions

Renewable Northwest argues that BPA should eliminate the IM rate for open access service on the Eastern Intertie and charge Network rates starting at Townsend in order to encourage use of BPA's 200-MW share of the Eastern Intertie and the development of wind resources in Montana. Renewable Northwest Br., BP-16-B-RN-01, at 1. Renewable Northwest adds that, although BPA's Eastern Intertie capacity was originally intended for the use of one party, that deal was terminated before the capacity was ever used for that purpose, and the capacity is now available under BPA's OATT. *Id.* at 4.

Renewable Northwest argues that the Draft ROD failed to address the relationship between elimination of the IM rate and Montana's compliance with the EPA's Clean Power Plan. Renewable Northwest Br. Ex., BP-16-R-RN-01, at 3. Renewable Northwest also argues that its proposal in BP-16 differs from its proposal in BP-14 in that it now proposes to charge Network rates starting at Townsend. *Id.* at 5. Renewable Northwest claims that this aspect of its proposal protects BPA's customers from costs and risks that they would otherwise face. *Id.* Renewable Northwest argues that there has been significant development of wind generation on both sides

of the Eastern Intertie where there is no IM rate. *Id.* at 6-7. However, Renewable Northwest argues, “not a single wind project has been developed for delivery over BPA’s share of unsubscribed Eastern Intertie capacity.” *Id.* at 7. Renewable Northwest claims that the wind generation that could use BPA’s Eastern Intertie capacity if the IM rate were eliminated would “go a long way toward helping the State of Montana (or another Northwest state) comply with the Clean Power Plan.” *Id.* at 8. Finally, Renewable Northwest argues that the Administrator should decide in this rate case that elimination of the IM rate would not serve as precedent for rolling in the Southern Intertie. *Id.* at 10.

JP15, M-S-R, WPAG, and JP12 oppose elimination of the IM rate. JP15 argues that no material fact has changed since the last two Administrators rejected similar proposals to roll BPA’s share of the Eastern Intertie costs into the Network rate. JP15 Br., BP-16-B-JP15-01, at 5. JP15 argues that retaining the IM rate would strike an appropriate balance between BPA’s obligation to promote widespread use of electric power and cost causation. *Id.* at 12. JP15 states that the Eastern Intertie serves only a small subset of BPA customers, and rolling its costs into the Network would expose BPA’s Network customers to a variety of costs and risks. *Id.* at 12-13.

WPAG also argues that elimination of the IM rate would expose Network customers to long-term cost risks. WPAG Br., BP-16-B-WG-01, at 16-18. M-S-R argues that the Eastern Intertie is radial to BPA’s system, that it is a generation tie, and that Federal Energy Regulatory Commission policy and the evidence in the record do not support rolling its costs into the Network rate. M-S-R Br., BP-16-B-MS-01, at 14-15. JP15, M-S-R, WPAG, and JP12 all argue that elimination of the IM rate could be a precedent for roll-in of the Southern Intertie costs to the Network rate, which would result in a much larger Network rate increase than would elimination of the IM rate. JP15 Br., BP-16-B-JP15-01, at 16; M-S-R Br., BP-16-B-MS-01, at 21-22; WPAG Br., BP-16-B-WG-01, at 15-16; JP12 Br., BP-16-B-JP12-01, at 2-3.

BPA Staff’s Position

In the Initial Proposal, BPA Staff proposed to retain the Eastern Intertie segment and the IM rate. Tenney *et al.*, BP-16-E-BPA-16, at 23. Staff testified that although separate delivery and intertie rates might be viewed as a discouragement of widest possible use, the status quo “strikes an appropriate balance between the widest diversified use requirement and cost causation.” *Id.* In rebuttal testimony, although Staff did not explicitly change its position, Staff said that Renewable Northwest’s proposal to eliminate the IM rate should be seriously considered. Metcalf *et al.*, BP-16-E-BPA-32, at 6. The impact on the Network rate of eliminating the IM rate could be either positive or negative, but in any case would be exceedingly small. *Id.* at 4. Elimination of the rate could encourage use of BPA’s unused Eastern Intertie capacity. *Id.* at 12. Elimination of the rate would tend to encourage development of renewable generation within the Pacific Northwest, help Northwest utilities meet needs for high-quality wind generation, and help Montana meet its obligations under the Environmental Protection Agency’s proposed Clean Power Plan. *Id.* at 8-11.

Evaluation of Positions

Renewable Northwest's proposal in BP-16 to eliminate the IM rate is the same as previous proposals to roll the portion of BPA's share of the Eastern Intertie that is sold into the Network. Metcalf *et al.*, BP-16-E-BPA-32, at 1-2. Renewable Northwest also argued in the BP-12 and BP-14 rate cases that costs of the Eastern Intertie should be rolled into the Network rate. Tenney *et al.*, BP-16-E-BPA-16, at 22. In both cases the Administrator rejected the proposal. JP15 Br., BP-16-B-JP15-01, at 5; Tenney *et al.*, BP-16-E-BPA-16, at 23. Renewable Northwest's current proposal to charge Network rates starting at Townsend is not different from its previous proposals. Implicit in earlier proposals, whether they were described as rolling in the Eastern Intertie or eliminating the IM rate, was that BPA would charge Network rates starting at Townsend. For example, in the BP-14 rate proceeding Renewable Northwest argued that "[e]liminating the duplicative rate would make the capacity available at the Network rate, instead of at the combined Network and IM Rates." RN Br. Ex., BP-14-R-RN-01, at 16.

Impact on Renewable Resource Development in Montana

Renewable Northwest claims that elimination of the IM rate would reduce transmission costs for Montana wind generation delivered to BPA's Network and therefore could support development of renewable generation in Montana. RN Br., BP-16-B-RN-01, at 5. Renewable Northwest notes that one of the purposes of BPA's statutes is "to encourage ... the development of renewable resources within the Pacific Northwest." *Id.* at 13, *citing* 16 U.S.C. § 839(1)(B). The high-quality wind resource areas identified by BPA Staff within the Vigilante and Glacier Electric Cooperative service areas are in the Pacific Northwest as defined by the Northwest Power Act. Metcalf *et al.*, BP-16-E-BPA-32, at 9-10 & Att. 2.

It is not clear, however, that the IM rate is a significant impediment to the development of wind generation in Montana. Renewable Northwest argues that this additional transmission charge undermines the competitiveness of Montana wind generation but offers no support for this conclusion. Renewable Northwest Br., BP-16-B-RN-01, at 5; Yourkowski, BP-16-E-RN-01, at 6. Renewable Northwest compared the cost of Montana wind generation to the cost of new natural gas facilities on BPA's network rather than to other wind generation. Yourkowski, BP-16-E-RN-01, at 6. Comparing Montana wind generation to other wind generation compels a different conclusion.

At a 40 percent capacity factor (the percentage of actual generation of a resource compared to its capacity), the IM rate adds \$2/MWh to the delivered cost of energy. *Id.* This is a relatively small addition to the total cost of over \$100/MWh. Baker *et al.*, BP-16-E-JP07-03, at 7. The average capacity factor for Montana wind generation is slightly lower at 38 percent but is still significantly higher than the expected capacity factor of 29 percent for Columbia Gorge wind generation, thus making Montana wind generation quite competitive. Metcalf *et al.*, BP-16-E-BPA-32, at 10. A presentation that Renewable Northwest itself cited in testimony shows the cost of Columbia Basin wind generation to be higher than the cost of Montana wind generation by more than \$2/MWh. *See* Baker *et al.*, BP-16-E-JP07-03, Att. A (*cited by* Yourkowski, BP-16-E-RN-01, at 6 n.6). Thus, even having to pay the IM rate, Montana wind generation has comparable or lower costs. Renewable Northwest argues that the development of wind

generation on both sides of the Eastern Intertie undermines these cost comparisons and ignores many other factors that impede the development of wind generation in Montana. Metcalf *et al.*, BP-16-E-BPA-32, at 7-8.

Moreover, although Montana's potential wind generation exceeds 9,000 MW, Metcalf *et al.*, BP-16-E-BPA-32, at 10, the absence of available transmission capability in Montana and on BPA's Network would make large-scale wind development unlikely. *Id.* at 7-8. NorthWestern Energy, the likely transmission provider for Montana wind generation to BPA's Network, currently posts only 49 MW of available transfer capability to BPA at Townsend. *Id.* at 7. BPA has only 184 MW of available capacity on the Eastern Intertie. *See id.* at 3. BPA's Network is constrained over the West of Garrison and West of Hatwai flowgates. Transmission requests in BPA's transmission queue that would use those flowgates exceed the available transfer capability. *Id.* at 8. Therefore, given current transmission constraints, it is unlikely that eliminating the IM rate would lead to significant renewable resource development in Montana. *Id.* at 7-8.

For similar reasons the evidence does not suggest that elimination of the IM rate would significantly influence Montana's compliance with the Clean Power Plan. Renewable Northwest argues that compliance with the plan would require between 303 and 798 MW of new wind capacity. Yourkowski & Decker, BP-16-E-RN-02, at 10. Under current conditions elimination of the IM rate would be unlikely to lead to a significant portion of the needed capacity.

JP07 and JP15 raise significant concerns regarding the costs and cost responsibility of the transmission upgrades and balancing capacity that would be necessary to support additional wind development. Baker *et al.*, BP-16-E-JP07-03, at 13-14; Baker *et al.*, BP-16-E-JP15-01, at 6-9. Renewable Northwest argues that the Draft ROD ignored the section of Renewable Northwest's initial brief that addressed these concerns. Renewable Northwest Br. Ex., BP-16-R-RN-01, at 8, *citing* Renewable Northwest Br., BP-16-B-RN-01, § II.D. In its initial brief, however, Renewable Northwest did not attempt to rebut the evidence on which the Draft ROD relied. Instead, it cited statements by BPA Staff that the impact on existing customers would likely be small. Renewable Northwest Br., BP-16-B-RN-01, at 14-15, *citing* Metcalf *et al.*, BP-16-E-BPA-32, at 3-4. However, Staff analyzed rate impacts based only on existing facilities. Metcalf *et al.*, BP-16-E-BPA-32, at 6. As noted in the Draft ROD, the real rate impacts would result from transmission upgrades and balancing capacity, which would be needed to support more wind development. BPA would be willing to work with the parties after the rate case to continue to discuss the potential for wind development in Montana. As part of those discussions, parties should discuss plans for upgrades and the provision of balancing reserves, including cost issues.

Southern Intertie Roll-In

JP15, WPAG, and M-S-R claim that elimination of the IM rate would be a precedent for rolling the costs of the Southern Intertie into the Network rate. JP15 Br., BP-16-B-JP15-01, at 16; WPAG Br., BP-16-B-WG-01, at 15-16; M-S-R Br., BP-16-B-MS-01, at 21-23. Rolling in the costs of the Southern Intertie to the Network rate would result in a 12.5 percent Network rate increase. Metcalf *et al.*, BP-16-E-BPA-32, at 12. A rate increase of this size could result in rate instability and rate shock. It would not be consistent with encouraging the widest possible use of

electric power at the lowest possible rates to consumers consistent with sound business principles.

In addition, because BPA's Southern Intertie capacity is fully reserved southbound, roll-in would not result in increased southbound reservations. *Id.* Therefore, the Network rate increase would not yield commensurate benefits to Network customers.

Because no party has proposed roll-in of the Southern Intertie costs to the Network rate and the IM rate is not being eliminated, it is unnecessary to consider other arguments regarding the Southern Intertie at this time. Renewable Northwest argues that the Administrator should conclusively find that eliminating the IM rate "would not set a precedent that would support potential future arguments to roll-in the Southern Intertie." Renewable Northwest Br. Ex., BP-16-R-RN-01, at 10. As noted above, however, roll-in of the Southern Intertie was not an issue in this case. Therefore, the record on this issue has not been developed. It would be inappropriate to reach a definitive decision on an undeveloped record, particularly when, as here, it is unnecessary to decide the issue.

Decision

The IM rate will not be eliminated. It is unlikely that, by itself, elimination of the IM rate would result in additional Montana wind generation. However, BPA is willing to work with interested parties after the rate case to discuss transmission issues relating to potential wind development in eastern Montana, including necessary upgrades and costs.

4.3.6 Network Segment Cost Allocation

Issue 4.3.6.1

Whether BPA should hold workshops regarding the Network segment cost allocation methodology after the BP-16 rate proceeding.

Parties' Positions

Although JP11 supports the 12 NCP method for the BP-16 rates, JP11 asks BPA to initiate a public process before the BP-18 rate case to discuss BPA's Network segment system planning criteria. JP11 Br., BP-16-B-JP11-01, at 3-5; JP11 Br. Ex. BP-16-R-JP11-01, at 2-3. Powerex supports JP11's recommendation. Powerex Br., BP-16-B-PX-01, at 30.

BPA Staff's Position

Staff proposed to allocate Network costs to NT customers based on the 12 NCP (non-coincident peak) method, the same method that BPA used to set rates in the BP-14 rate case. Fredrickson *et al.*, BP-16-E-BPA-8, at 14-15. The cost allocation method was fully litigated in the BP-14 rate case, and the Administrator fully responded to arguments about why BPA's transmission system planning approach is consistent with a 12 NCP methodology. Fredrickson *et al.*, BP-16-E-BPA-29, at 2-3.

Evaluation of Positions

Whether or not BPA's planning approach is consistent with a 12 NCP methodology was fully evaluated and decided in the BP-14 rate case. Administrator's Final Record of Decision, BP-14 Power and Transmission Rate Proceeding, BP-14-A-03, at 145-65 (June 2013) (BP-14 ROD). JP11 acknowledges this fact but asserts that new evidence presented in pre-rate-case workshops supports a different cost allocation, and that BPA should hold workshops on cost allocation before the BP-18 rate case. JP11 Br., BP-16-B-JP11-01, at 3, 4-5; JP11 Br. Ex., BP-16-R-JP11-01, at 2-3. Powerex supports JP11's recommendation. Powerex Br., BP-16-B-PX-01, at 30.

BPA is not bound by Commission precedent when setting rates. Nonetheless, the BP-14 ROD amply demonstrates that the Administrator considered BPA's planning approach, contractual rights to capacity, allocation of diversity benefits, and Commission precedent in depth when choosing the 12 NCP method. BP-14 ROD at 146-50, 152-58, 160-65. JP11 supported the use of the same method in this rate case. Russell *et al.*, BP-16-E-JP11-02, at 10. It has offered no compelling reason why BPA should initiate a public process after the close of the rate case to discuss the cost allocation method further. Nevertheless, JP11 may raise cost allocation issues during the normal course of workshops held before the start of the BP-18 rate case.

Decision

BPA will not initiate workshops regarding the Network segment cost allocation method after the BP-16 rate proceeding. Any party may raise the issue in the normal workshops held before the start of the BP-18 rate case.

This page intentionally left blank.

5.0 PARTICIPANT COMMENTS

This chapter summarizes and evaluates the comments of participants in the rate case. As defined in BPA's procedures for conducting rate proceedings, "participants" are persons that comment on BPA's rate proposal but do not take part in the formal hearing process with the responsibilities of "parties." Parties to the case file testimony and briefs and thus are not allowed to submit comments as participants. Participant comments are part of the official record of the rate proceeding and are considered when the Administrator makes his final decisions.

On December 4, 2014, BPA published in the Federal Register a Notice of "Fiscal Year (FY) 2016–2017 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment." 79 Fed. Reg. 71,984 (2014). The Federal Register notice may be viewed at the link: <https://www.federalregister.gov/articles/2014/12/04/2014-28463/fiscal-year-fy-2016-2017-proposed-power-and-transmission-rate-adjustments-public-hearing-and>. The Federal Register notice set a deadline of February 26, 2015, for participant comments.

BPA received three comments through the participant comment process. Summaries of the participant comments, and BPA's responses, are provided below.

Comment BPRP140001. Participant Charles Pace stated that setting February 26, 2015, as a final date for participants to submit written comments violates the procedural requirements in the Northwest Power Act and limits BPA's ability to develop a full and complete record. Dr. Pace stated: "This is in violation of the statutory requirements of section 7(i)(2)(A) of the Northwest Power Act, 94 Stat. 2726, which, in relevant part, provides as follows: ANY PERSON shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of ANY MATERIAL submitted by ANY OTHER PERSON OR the ADMINISTRATOR, 16 U.S.C. 839e(i)(2)(A) (emphasis added). By establishing February 26, 2015, as the close of opportunity for participants to submit comments, all persons other than parties are denied the procedural protections established by Congress to offer refutation or rebuttal of material submitted by other persons, including the Administrator, after February 26, 2015."

Dr. Pace stated that BPA should establish a date at the close of the hearing for participant comments so that participants could comment on all material submitted, including, among other things, rebuttal testimony, briefs, and the Draft Record of Decision. Finally, he added that participants should be allowed to participate in the hearing and have the opportunity to engage in "non-dilatory" cross-examination (questioning that does not delay the process).

Comment BPRP0002. Dr. Pace submitted a second comment that corrects a typographical error in his first comment.

Response to Comments BPRP0001 and 0002. Setting a reasonable limit on the time for submitting participant comments (such as the February 26 limit) does not violate the procedural requirements of the Northwest Power Act. Dr. Pace's underlying concern appears to be that BPA denied participants procedural protections when it set the date for public comment before

the filing of parties' rebuttal cases, cross-examination, filing of briefs, and publication of the Draft Record of Decision. The Northwest Power Act requires the Administrator to publish notice of the "proposed rates" in the Federal Register, 16 U.S.C. § 839e(i)(1), and requires the hearing officer to conduct a hearing to "receive public comment in the form of written and oral presentation of views, data, questions, and argument related to *such proposed rates.*" *Id.* § 839e(i)(2) (emphasis added). That is, the public has the right to respond to BPA's initial rate proposal.

BPA published its Initial Proposal on December 10, 2014, almost three months before the date set for the end of receipt of public comments. As a result, all participants had adequate opportunity to review and comment on BPA's rate proposal. In addition, the date for participant comments was more than three weeks after the filing of the parties' direct cases, allowing participants the opportunity to comment on that material as well.

It would be unwieldy and administratively burdensome to allow participants to take part in the hearing and to conduct cross-examination. The Administrator must be allowed to exercise the discretion necessary to establish the scope of the proceeding in order to allow the proceeding to be conducted in an orderly and timely manner.

Comment BPRP0003. The Governor of Montana filed a participant comment stating that BPA should eliminate the Montana Intertie rate (IM rate). The governor stated: "Montana power generators using BPA's Eastern Intertie continue to pay both the IM rate and the Network rate, and this duplicative charge negatively impacts energy development in Montana." The governor added that elimination of the IM rate would help Montana comply with the EPA's Clean Power Plan and encourage wider use of BPA's Eastern Intertie. Finally, the governor stated, it would "significantly benefit the economy in Montana, provide regional benefits, and contribute to domestic energy security."

Response to comment BPRP0003. This issue has been litigated in the rate case and is addressed in Record of Decision section 4.3.5.

6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

6.1 Introduction

BPA has assessed the potential environmental effects that could result from decisions being made through the 2016 Wholesale Power and Transmission Rate Adjustment Proceeding, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* The NEPA analysis is conducted separately from the formal rate process.

BPA previously prepared a policy-level Business Plan Final Environmental Impact Statement (Business Plan EIS), which evaluates the environmental impacts of a range of business structure alternatives that include, among other things, various rate designs for BPA's power and transmission products and services. DOE/EIS-0183, June 1995. In August 1995 the BPA Administrator also issued the Business Plan ROD, which adopted the Market-Driven alternative from the Business Plan EIS. As discussed in more detail below, the BP-16 rate proposal falls within the scope of the Market-Driven alternative and is not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS. BPA will therefore tier the decision to implement the BP-16 rates to the Business Plan ROD.

Although BPA is doing so, this rate proposal is the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to BPA. Specifically, this rate proposal falls within Categorical Exclusion B4.3, found at 10 C.F.R. § 1021, subpt. D, app. B (2015), which provides for the categorical exclusion from NEPA documentation of “[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits.” Nonetheless, BPA has laid out a strategy in the Business Plan EIS and ROD for NEPA compliance concerning future business-related decisions and contends that a ROD tiered to the Business Plan ROD is an appropriate means for ensuring NEPA consideration of the BP-16 rates.

6.2 Business Plan EIS and ROD

The Business Plan EIS was prepared in response to the need for an adaptive business policy that would allow BPA to be more responsive to the evolving and increasingly competitive wholesale electricity market while still meeting its business and public service missions. Accordingly, BPA designed the Business Plan EIS to support a wide array of business decisions, including decisions related to rates for products and services in rate cases in 1995 and thereafter. Business Plan EIS § 1.4. BPA identified several purposes for consideration, including achieving strategic business objectives; competitively marketing BPA's products and services; providing for equitable treatment of Columbia River fish and wildlife; achieving BPA's share of the Northwest Power and Conservation Council's conservation goal; establishing rates that are easy to understand and administer, stable, and fair; recovering costs through rates; meeting legal mandates and contractual obligations; avoiding adverse environmental impacts; and establishing

productive government-to-government relationships with Indian Tribes. *Id.* § 1.2; Business Plan ROD §§ 5 & 6.

BPA's Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. Business Plan EIS § 2.4. Table 2.4-1 of the Business Plan EIS shows how the alternatives evaluated in the Business Plan EIS treat these issues. Four policy options, or modules, were developed in the Business Plan EIS to allow variations of the alternatives in key areas, including rate design.

The alternatives and modules are designed to cover the range of options for the important issues affecting BPA's business activities, as well as the impacts of those options. Variations can be assembled by matching issues and substituting modules among the six alternatives. *Id.* § 2.1.2. All of the alternatives and modules are examined under two widely different hydro system operations strategies that served as "bookends" for reasonably possible operations of the FCRPS. These alternatives thus represent a range of reasonable alternatives for BPA's business activities and BPA's ability to balance costs and revenues.

The Business Plan EIS focuses on BPA relationships to the market. Business Plan EIS § 2.1. BPA's business decisions, such as setting or revising rates, do not have a direct effect on the environment; rather, environmental impacts are determined indirectly by market responses to BPA's marketing actions and business decisions. *Id.* §§ 2.1.5 & 4.1.2. These market responses, discussed in detail in section 4.2 of the Business Plan EIS, are resource development (including conservation); resource operation; transmission development and operation; and consumer behavior. They can result in a variety of environmental impacts, including air, land, and water impacts, as well as socioeconomic impacts. *Id.* Figures 2.1-1 & S-2. For wholesale power and transmission ratemaking, the Business Plan EIS describes how BPA rates can affect the environment through market responses. *Id.* § 2.4.2 and Figure 2.4-1.

Thus, the Business Plan EIS is based on a relationship analysis. BPA has quantitatively and qualitatively evaluated relationships between variables in the short run and assumed that these relationships will hold true in the long run. This relationship-based approach serves as the foundation for the environmental analyses of alternatives and modules in sections 4.4 and 4.5 of the Business Plan EIS.

To determine the potential environmental consequences of the various alternatives, the Business Plan EIS identifies general market responses to key policy issues. *Id.* Table 4.2-1. It discusses the market responses for products and services for each of the alternative business directions and for rates. *Id.* §§ 4.2.1 & 4.2.2. The market responses and the environmental consequences are discussed both in general terms and in terms specific to each alternative. *Id.* § 4.3. Table 4.3-1 details the typical environmental impacts from power generation and transmission. Section 4.4 presents the market responses and environmental impacts by alternative under each of the two bookend hydro operation scenarios. Section 4.4.3 also includes an illustrative numerical

example. Table 4.4-19 summarizes the key environmental impacts by alternative. *Id.* § 4.4.3.8. Appendix B to the Business Plan EIS includes an extensive evaluation of rate design, including market response and environmental impacts. *Id.* Appendix B. As can be seen from the environmental analyses summarized in Tables 4.4-19 and 4.4-20, differences in total environmental impacts among the alternatives are relatively small.

The Business Plan EIS evaluates each of the alternative business directions against the purposes for the action to determine how well each of the alternatives meets the need. *Id.* § 2.6.5. Based on the evaluation of potential environmental impacts and the comparison of each alternative to the identified purposes, in the Business Plan ROD the Administrator adopted the Market-Driven alternative as the Agency's overall business policy. Business Plan ROD § 6. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also assists BPA in maintaining the financial strength necessary to continue a relatively high level of support for public service benefits, such as energy conservation and fish and wildlife mitigation activities, while keeping BPA rates as low as possible.

Recognizing that the Administrator could select a variety of actions, BPA included many mitigation response strategies in the Business Plan EIS and ROD to address changed conditions and allow the Agency to balance costs and revenues. These response strategies include measures that BPA could implement to increase revenues (including rate measures), decrease spending, and/or transfer costs if its costs and revenues do not balance. Business Plan EIS § 2.5; Business Plan ROD § 7. These strategies enable BPA to meet its financial, public service, and environmental obligations while remaining competitive. In the Business Plan ROD, the Administrator decided to implement as many response strategies, or equivalents, as necessary to balance costs and revenues. Business Plan ROD § 7.

The Business Plan EIS and ROD also document a decision strategy for tiering subsequent business decisions to the Business Plan ROD. Business Plan EIS § 1.4; Business Plan ROD § 8. The BPA Administrator reviews the Business Plan EIS and ROD to determine whether each such decision falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the proposed decision is found to be within the scope of this alternative, the Administrator may tier his decision under NEPA to the Business Plan ROD. Business Plan ROD § 8. Tiering a ROD to the Business Plan ROD helps BPA delineate its business decisions clearly and provides a logical framework for connecting broad policy decisions to specific actions. Business Plan EIS § 1.4.

Since 1995, over 40 business decisions have been implemented by tiering RODs for each decision to the Business Plan ROD. RODs tiered to the Business Plan ROD have been completed for a broad array of BPA business decisions, such as rates for power products and services, rates for transmission products and services, power sales contracts, transmission agreements, power interconnection projects, power subscription, interconnection of energy development projects, and cost recovery adjustment clauses. Through these RODs, BPA also has evaluated the accuracy of its assumption, made in the Business Plan EIS, that the short-term relationships among variables would hold true in the long term. BPA has found that these relationships have stayed largely the same with respect to environmental concerns.

In April 2007, BPA completed a review of the Business Plan EIS and ROD through a Supplement Analysis, as provided for in NEPA regulations that apply to BPA. The Supplement Analysis was prepared to assess whether the Business Plan EIS still provides an adequate evaluation, at a policy level, of environmental impacts that may result from BPA's current business practices and whether these practices are still consistent with the Market-Driven alternative adopted in the Business Plan ROD. The Supplement Analysis evaluated changes that have occurred in the electric utility market and the existing environment and considered developments that have occurred in BPA's business practices and policies. It found that the Business Plan EIS's relationship-based and policy-level analysis of potential environmental impacts from BPA's business practices remains valid and that BPA's current business practices are still consistent with BPA's Market-Driven approach. The Business Plan EIS and ROD thus continue to provide a sound basis for making determinations under NEPA concerning BPA's policy-level decisions.

In July 2007, BPA issued a ROD for its Long-Term Regional Dialogue Policy (RD Policy), through which BPA adopted a policy on its long-term power supply role after FY 2011. The RD Policy was the result of a Regional Dialogue process that began in April 2002 with the intent to define BPA's power supply and marketing role in a way that meets key regional and national energy goals in the short term and long term. Considering the depth and complexity of many issues, BPA determined that it would address the issues in two phases. The first phase of Regional Dialogue addressed issues that had to be resolved to replace power rates that expired in September 2006. *See* Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (Feb. 2005) (Short-Term Policy). The second phase addressed longer-term issues, culminating in BPA's RD Policy ROD. This policy provides BPA's customers with greater clarity about their Federal power supply so they can effectively plan for the future and, if they choose, make capital investments in long-term electricity infrastructure. It was during the Regional Dialogue processes that a tiered rate structure was introduced, and the RD Policy ROD included adoption of a policy concerning tiered rates. As part of its decisionmaking process for the RD Policy, BPA also prepared a NEPA ROD that found the RD Policy to be consistent with the Market-Driven alternative analyzed in the Business Plan EIS and adopted in the Business Plan ROD. BPA therefore tiered the NEPA ROD for the RD Policy to the Business Plan EIS and ROD.

In November 2008, BPA issued a ROD for its Tiered Rate Methodology (TRM) rate proceeding, which was conducted to implement the policy for tiering Priority Firm Power (PF) rates that was adopted in BPA's RD Policy ROD. The TRM is a rate design methodology that prescribes BPA's design of PF Public rates through FY 2028. The TRM ROD adopted basic design and methodology components for tiered rates that are consistent with the policy for tiering PF rates described in the RD Policy. After BPA issued the TRM ROD, BPA and representatives of its PF Preference rate customers identified eight proposed modifications to the TRM to enhance consistency with Regional Dialogue power sales contracts and address errors or unintended consequences. BPA conducted the TRM Supplemental Rate Proceeding to address these TRM revisions, all of which were administrative in nature. In September 2009, BPA issued its TRM Supplemental ROD, which adopted a revised TRM incorporating the eight TRM modifications. Both the TRM ROD and the TRM Supplemental ROD evaluated the potential for environmental

effects related to implementation of the TRM, consistent with NEPA. These evaluations found that implementation of the TRM, both as originally adopted and as revised, is consistent with the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD (August 15, 1995), as well as with the RD Policy and its associated NEPA ROD.

6.3 Environmental Analysis

The Business Plan EIS and ROD were reviewed to determine whether the BP-16 rate proposal is adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. The Business Plan EIS includes analyses of the same rate-related issues associated with decisions being made through the BP-16 rate case. The key policy issues analyzed in the Business Plan EIS include several rates-related decisions, and the modules include a range of rate design options, including tiered rates, streamflow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts.

As discussed above, the Business Plan EIS identifies general market responses to BPA actions, such as establishing or revising rates, and these market responses are the source of potential environmental impacts. Specifically, the primary potential environmental impacts of power and transmission rates stem from the choices customers make for generation resources and conservation and transmission provider. Business Plan EIS §§ 4.2.2.2 & 4.5.2. For example, increasing rates may cause more customers to seek energy on the market, may encourage customers to develop their own generation resources, or may cause more customers to seek alternative transmission providers or construct new transmission facilities. If any of these were to occur, customers might develop or purchase thermal generation, which in theory could be less expensive. The cost of transmission could also influence customer decisions on resource siting or the marketability of resource output. This market response could increase various environmental impacts, such as air pollution from nitrogen, sulfur, and carbon emissions and water- and land-use impacts.

It is expected that these types of indirect environmental effects from market responses to the BP-16 rates as well as their potential to occur would be consistent with the effects identified in the Business Plan EIS. The relationships between BPA's rates-related actions and market responses have not changed significantly relative to environmental concerns since they were analyzed in the Business Plan EIS. In addition, hydro system operations will not be affected by the BP-16 rates. BPA already has mechanisms in place to serve its contractual obligations and to market power and services with available resources consistent with the operating constraints that apply to the hydro system, consistent with the Business Plan EIS and ROD. Business Plan EIS § 1.5.6; Business Plan ROD at 4.

Based on the review of the Business Plan EIS and ROD, the BP-16 rates are a direct application of the Market-Driven alternative, and the rates remain consistent with the type of rate designs identified and evaluated in the Business Plan EIS. The issues related to this proposal are consistent with the analysis of key policy issues related to power and transmission products and

services identified for the Market-Driven alternative. *Id.* §§ 2.2.3 & 2.6. In addition, the BP-16 rates do not differ substantially from the types of rate designs considered and evaluated in the Business Plan EIS. *Id.* §§ 2.4.1.6, 2.4.2.2, 2.4.4, and Appendix B. Therefore, the specifics of the 2016 Wholesale Power and Transmission Rate Adjustment Proceeding fall within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD. Because of these consistencies, implementation of this rate proposal will not result in significantly different environmental impacts from those examined for the Market-Driven alternative in the Business Plan EIS.

Furthermore, the BP-16 rates will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD. This alternative was selected as BPA's business direction because it allows BPA to (1) recover costs through rates; (2) competitively market BPA's products and services; (3) develop rates that meet customer needs for clarity and simplicity; and (4) continue to meet BPA's legal mandates.

The BP-16 rates provide a competitive rate structure that includes various mechanisms to account for potential revenue shortfalls. The rate proposal thus allows BPA to continue to recover its costs through its rates while remaining competitive and is consistent with the general approach to setting rates and managing and responding to risk that was developed in the Market-Driven alternative and continued through subsequent rate cases. The rate design has been made as clear and simple as possible, given the various types of products and services covered. Finally, the BP-16 rates will allow BPA to meet all of its applicable legal mandates. Accordingly, the BP-16 rates are consistent with these aspects of the Market-Driven Alternative.

6.4 Public Comments

The Federal Register Notice for the BP-16 rate proceeding noted that comments regarding the potential environmental effects of the Initial Proposal received by the comment deadline for participant comments would be considered by BPA's NEPA compliance staff in the NEPA process conducted for this proposal. 79 Fed. Reg. 71,984, 71,987–88 (Dec. 4, 2014). No comments concerning NEPA compliance or potential environmental effects of the proposal were received before the comment deadline, February 26, 2015.

6.5 NEPA Decision

Based on a review of the Business Plan EIS and ROD, the BP-16 rate proposal falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. The BP-16 rates are not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS and will assist BPA in accomplishing the goals related to the Market-Driven alternative that are identified in the Business Plan ROD. Therefore, the decision to implement the BP-16 rates is tiered to the Business Plan ROD.

7.0 CONCLUSION

As required by law, the rates established and adopted in this Final Record of Decision have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be the lowest possible rates consistent with sound business principles, to encourage the widest possible use of BPA's power, and to satisfy BPA's other ratemaking obligations. The transmission and ancillary services rates have been designed to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. Finally, all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA has established its rates pursuant to section 7(i) of the Northwest Power Act. BPA has evaluated the potential environmental impacts related to the rates established and adopted in this Final Record of Decision, consistent with NEPA. In this instance, the FY 2016–2017 final power and transmission rate proposals fall within the scope of the Business Plan EIS and are not expected to result in environmental impacts that are significantly different from those examined in that EIS. I have considered the environmental analysis contained in the Business Plan EIS in making the decisions in this Final Record of Decision, and the NEPA decision for the rate proposals is tiered to the Business Plan ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the accompanying BP-16 Power Rate Schedules and General Rate Schedule Provisions and the Transmission, Ancillary and Control Area Service Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission requirements, 18 C.F.R. § 300.10(g), I hereby certify that the power and transmission rate schedules and general rate schedule provisions adopted herein contain the lowest possible rates consistent with sound business principles and are consistent with other applicable laws.

Issued at Portland, Oregon, this 23rd day of July, 2015.

/s/ Elliot E. Mainzer

Elliot E. Mainzer

Administrator and Chief Executive Officer

This page intentionally left blank.

Appendix A

Settlement Agreement

PARTIAL SETTLEMENT AGREEMENT

Bonneville Power Administration 2016 Rate Case Generation Inputs and Transmission Ancillary and Control Area Services Rates

THIS PARTIAL SETTLEMENT AGREEMENT, including Attachments 1, 2, and 3 (“AGREEMENT”), dated and effective as of the date established pursuant to section 3 of this Agreement, is among the Bonneville Power Administration (“Bonneville”) and the BP-16 rate case parties (in the singular, “Party,” in the plural, “Parties”).

WHEREAS

- A. Starting in October 2013, Bonneville and the Parties have been engaged in public meetings to reach agreement on the rates for certain transmission ancillary and control area services for the FY 2016-2017 Rate Period (“Rate Period”);
- B. Bonneville and the Parties wish to settle their disputes concerning generation inputs and transmission ancillary and control area services rates for the Rate Period;
- C. Bonneville and the Parties recognize that both the rate structure and the operations related to the integration of variable energy resources and dispatchable energy resources in Bonneville’s balancing authority area are in a transitional period; that there is considerable disagreement about how to design Bonneville’s transmission ancillary and control area services rates, terms and conditions; and that there is disagreement about the allocation of balancing reserve capacity and energy costs; and
- D. The purpose of this Agreement is to settle those differences for the Rate Period, without precedent for subsequent rate periods, so that Bonneville and the Parties can work collaboratively on developing operational tools, terms and conditions, and proposals for rates and the allocation of costs for the services necessary to balance the system in future rate periods.

NOW, THEREFORE, Bonneville, the undersigned Party signatories (“Party Signatories”), and Parties who otherwise indicate assent to this Agreement by not objecting to this Agreement or the Settlement Proposal (as defined in section 1) on the record of the BP-16 rate proceeding pursuant to section 3 (“Non-Objecting Parties”, and collectively with the Party Signatories, the “Assenting Parties”) agree to the following:

1. In the BP-16 rate proceeding, Bonneville staff will propose that the Administrator adopt a proposal to establish the costs of generation inputs and rates for transmission ancillary and control area services for the Rate Period (“Settlement Proposal”). The Settlement

Proposal will include only the terms specified in Attachment 1, the rate schedules and general rate schedule provisions specified in Attachment 2, the terms in Attachment 3, and the terms of this Agreement.

2. During the Rate Period, Bonneville and the Assenting Parties will abide by the terms specified in Attachment 1 and this Agreement.
3. Bonneville will notify the Hearing Officer of the Agreement and move the Hearing Officer to: (1) require any Party that did not sign or assent to the Agreement to state its objection to the Settlement Proposal, the basis for its objection, and to identify each issue included in the Settlement Proposal that such Party chooses to preserve in the BP-16 rate proceeding within 5 days of the date interventions are granted in the rate proceeding; and (2) specify that any Party that does not state its objection to the Settlement Proposal on such date will waive its rights to preserve any objections to the Settlement Proposal and shall be treated as an Assenting Party for all purposes under this Agreement and on the record in the BP-16 rate proceeding. Unless this Agreement terminates under the terms set forth in sections 4 and 5 below, this Agreement will become effective on November 12, 2014, and will terminate on September 30, 2017. If a Party has not preserved any issues originally through an objection to the Settlement Proposal, the Party waives its right to preserve such issue.
4. If, in response to the Hearing Officer's order made pursuant to section 3, any Party states an objection to the Settlement Proposal, Bonneville or any Assenting Party will have three business days from the date of the objection to withdraw its assent to the settlement. If Bonneville or any Assenting Party withdraws its assent to the settlement, Bonneville shall promptly meet with any other interested rate case parties to discuss how to proceed.
5. If the Administrator does not adopt the Settlement Proposal in the BP-16 Final Record of Decision, this Agreement and the Settlement Proposal will terminate upon the date the Administrator declines to adopt the Settlement Proposal.
6. Waiver
 - a. Preservation of BP-16 ACS Rates and Settlement Proposal
 - i. The Parties agree that this is a black box settlement. If the Administrator adopts the Settlement Proposal, Bonneville and the Assenting Parties

agree not to contest this Agreement or its implementation pursuant to its terms, including the Settlement Proposal and rates and rate schedule provisions in Attachment 2, from the effective date through September 30, 2017.

- ii. The Assenting Parties agree to waive their rights to cross-examination and discovery with respect to the Settlement Proposal, except in response to issues raised by any party in the BP-16 rate proceeding that is not an Assenting Party to this Agreement.

b. Reciprocity

In the event that this Agreement is determined to be inconsistent or incompatible with a reciprocity transmission tariff, the Assenting Parties agree that this Agreement shall nonetheless remain in effect for the remainder of the Rate Period.

c. No Precedent or Issue Preclusion beyond the Rate Period

- i. Bonneville and the Assenting Parties understand, and will not argue otherwise, that this Agreement does not constitute consent or agreement in any future rate proceedings to the transmission ancillary and control area services rates and rate schedule provisions in Attachment 2 or to any rate, charge, or rate schedule provision, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such matters; and
- ii. The Assenting Parties and Bonneville acknowledge that this Agreement is a package, and that acceptance of the package does not create or imply any agreement with individual components of the package. Therefore, the Assenting Parties and Bonneville agree that they will not assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by any Assenting Party, the Hearing Officer, the Administrator, the Federal Energy Regulatory Commission (“Commission”), or a court, creates or implies: (1) any procedural or substantive precedent (including, but not limited to, a substantive precedent with respect to rate design and a 3 MW dead band under the Dispatchable Energy Resource Balancing Service rate); (2)

agreement to any particular or individual treatment of costs, expenses, or revenues; (3) agreement to any particular interpretation of Bonneville's statutes; (4) any precedent under any contract or otherwise between Bonneville and any Party; or (5) any basis for supporting any Bonneville rate, terms or conditions for any period after the Rate Period.

7. Reservation of rights

- a. Except as provided in section 6(a) above, no Assenting Party waives any of its rights, under Bonneville's enabling statutes, the Federal Power Act, or other applicable law, to pursue dispute resolution procedures consistent with Bonneville's open access transmission tariff or to pursue any claim that a particular charge, methodology, practice, or rate schedule has been improperly implemented.
- b. Bonneville and the Assenting Parties reserve the right to file new complaints, petitions, or litigation related to any rates, terms and conditions, or other matters that are not a part of the Settlement Proposal.
- c. Notwithstanding section 6(a), but subject to section 8 of this Agreement, the Assenting Parties may seek review of the reliability tool described in Section 10 of Attachment 1.
- d. Bonneville and the Assenting Parties reserve the right to litigate any transmission or power rate at issue in the BP-16 rate proceeding that is not included in the Settlement Proposal. In addition, Bonneville reserves the right to propose changes to the transmission and power rates, rate schedules, and associated general rate schedule provisions for services that are not included in the Settlement Proposal.
- e. Bonneville and the Assenting Parties reserve the right to litigate and advance any arguments: (1) in proceedings that are pending before the Commission, the United States Court of Appeals for the Ninth Circuit, or any other judicial forum as of the effective date of this Agreement; and (2) in administrative or judicial review, now or hereafter pending, of such proceedings (collectively, "Pending Proceeding(s)").

- f. Bonneville and the Assenting Parties reserve the right to respond during the Rate Period to any new filings, protests, or claims, by Bonneville or others; however, Bonneville and the Assenting Parties will not support a challenge to any rates, terms and conditions, or other matters described in this Agreement.
 - g. The Parties specifically acknowledge that the self-supply and unbundling components of BPA's Self Supply of Balancing Services Business Practice, Version 1, and any successor thereto is not part of this Settlement Agreement for purposes of Sections 7(b) and 7(d). Nothing in this Section 7(g) is intended to give a Party the right to challenge the Mid-Rate Period Adjustment provisions under sections 7 and 8 in Attachment 1.
8. If because of a legal challenge, Bonneville would be required to materially modify or discontinue the rates, terms, and conditions provided in this Agreement, including but not limited to the use of its balancing reserve capacity-related curtailment protocols during the Rate Period, Bonneville will seek, and the Assenting Parties agree to support, or not contest, a stay of enforcement of that ruling until after the Rate Period and Bonneville may, but shall not be required to, initiate a section 7(i) rate proceeding to revise or supplement any of the rates in Attachment 2.
9. Attachment 1 (Rate Period Terms), Attachment 2 (Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions) and Attachment 3 (Inter-Business Line Allocations) are incorporated by reference into this Agreement.
10. Section 6(c) (No Precedent or Issue Preclusion beyond the Rate Period) of this Agreement will survive termination or expiration of this Agreement.
11. Nothing in this Partial Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's rates or the Assenting Parties' rights to challenge such revisions.

This Agreement may be executed in counterparts.

[Print Party Name]

By: _____

Name: _____
(Print/Type)

Title: _____

Date: _____

ATTACHMENTS

Attachment 1, Rate Period Terms

Attachment 2, Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions

Attachment 3, Inter-Business Line Allocations

ATTACHMENT 1, RATE PERIOD TERMS

1. **Term.** The terms and conditions in this Attachment 1 will apply to and will be binding on Bonneville and the Assenting Parties during the Fiscal Year (FY) 2016-2017 Rate Period (“Rate Period”), but must expire and not survive in any form after September 30, 2017.
2. **Imbalance Service.** Bonneville shall attempt to provide an imbalance service based on the incremental (*inc*) and decremental (*dec*) reserve quantities described in this Attachment 1. Bonneville shall use reasonable efforts in accordance with this Agreement to provide an *inc* imbalance service that is equal to or better than the service provided in FY 2014. This is estimated to be less than 10 curtailment events in October, November, December, January, February, March, August and September (“Non-Spring Months”) and less than 30 curtailment events in April, May, June and July (“Spring Months”).
3. **Dec Reserve.** Bonneville will use reasonable efforts to provide 900 MW of *dec* balancing reserve capacity from the Federal Columbia River Power System (“FCRPS”) during all hours of the Rate Period. Bonneville and the Assenting Parties acknowledge that operational constraints and significant energy imbalance accumulations during operationally constrained periods of the year may limit Bonneville’s ability to provide 900 MW of *dec* balancing reserve capacity from the FCRPS at times during the Rate Period. Bonneville shall not make any *dec* balancing reserve capacity acquisitions unless Bonneville determines *dec* balancing reserve capacity acquisitions are necessary to maintain system reliability.
4. **Inc Reserve (Non-Spring Months).** Bonneville will use reasonable efforts to provide a total of 910 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment described in section 8 of this Attachment 1 and Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2) for all hours in Non-Spring Months of each fiscal year in the Rate Period. Notwithstanding any other section in this Agreement and except as a direct result of Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2, Bonneville is not obligated to provide more than 910 MW of *inc* balancing reserve capacity, FCRPS-sourced or otherwise, in any hour during the Non-Spring Months of each fiscal year in the Rate Period.
 - a. **FCRPS Source.**
 1. Bonneville will plan to provide up to 900 MW of the Non-Spring Month *inc* balancing reserve capacity from the FCRPS. To the extent Bonneville is unable to provide 900 MW of *inc* balancing reserve capacity from the FCRPS, Bonneville will attempt to, but is not obligated to, replace that capacity with third-party *inc* reserve capacity purchases. In making such acquisitions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Non-Spring Months.

2. In the event Bonneville is unable to make available 900 MW of *inc* balancing reserve capacity from the FCRPS under section 4(a)(1) above, Bonneville Power Services will issue a refund to Bonneville Transmission Services in the amount of \$0.29/kW/day for the planned capacity that was not available from the FCRPS. The total amount refunded by Bonneville Power Services under this section will be added to the Annual Budget described in Section 6(a) of this Attachment 1.
3. Bonneville may provide, at its sole discretion, any additional amounts of *inc* balancing reserve capacity from the FCRPS because of the conditions described in Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedule in Attachment 2. Such additional amounts of *inc* balancing reserve capacity will be provided at a cost of \$0.29/kW/day.
 - b. **Third-Party Source.** Bonneville shall attempt to acquire 10 MW of *inc* balancing reserve capacity on a quarterly basis.
5. **Inc Reserve (Spring Months).** Bonneville will use reasonable efforts to provide at least 600 MW of *inc* balancing reserve capacity for all hours in Spring Months of each fiscal year in the Rate Period. Bonneville is not obligated to provide more than 910 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment as described in section 8 of this Attachment 1 and Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2), FCRPS-sourced or otherwise, in any hour during the Spring Months of each fiscal year in the Rate Period.
 - a. **FCRPS source.** Bonneville will provide from the FCRPS at least 400 MW of *inc* balancing reserve capacity for all hours of the Spring Months of each fiscal year in the Rate Period. To the extent Bonneville is unable to provide 400 MW of *inc* balancing reserve capacity from the FCRPS, Bonneville will attempt to, but is not obligated to, replace that capacity with third-party *inc* balancing reserve capacity purchases. In making such acquisitions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Non-Spring Months.
 - b. **Refund for replacement.** In the event Bonneville is unable to make available 400 MW of *inc* balancing reserve capacity from the FCRPS under section 5(a) above, Bonneville Power Services will issue a refund to Bonneville Transmission Services in the amount of \$0.29/kW/day for the planned capacity that was not available from the FCRPS. The total amount refunded by Bonneville Power Services under this section will be added to the Annual Budget described in Section 6(a) of this Attachment 1.

- c. **Balancing Reserve Capacity purchases on Forward Basis.** Bonneville shall attempt to acquire at least 200 MW of *inc* balancing reserve capacity (in addition to 400 MW from the FCRPS) for April, May, and June in each fiscal year at least 25 days in advance or such longer period as Bonneville determines is practicable (“Forward Basis”), except that Bonneville is not obligated to make any individual purchase of balancing reserve capacity if the price for that purchase would exceed \$0.29/kW/day. Nothing in this subsection limits Bonneville’s right to provide balancing reserve capacity on a Forward Basis from the FCRPS at a cost of \$0.29/kW/day funded from the Annual Budget before making any purchases from third parties.
 - d. **FCRPS source before third party source.** Before attempting to acquire *inc* balancing reserve capacity from a third party, Bonneville will assess whether the balancing reserve capacity required to meet its forecast need is available from the FCRPS. If Bonneville determines that more than 400 MW of *inc* balancing reserve capacity is available from the FCRPS, Bonneville shall provide that *inc* balancing reserve capacity from the FCRPS. In that instance, the cost of Spring Month *inc* balancing reserve capacity that Bonneville provides from the FCRPS above 400 MW will be at a cost of \$0.29/kW/day and will be funded by the Annual Budget.
 - e. **Third Party Source.** If Bonneville determines that the FCRPS is not capable of producing more than 400 MW of *inc* balancing reserve capacity as provided in section 5(a) above at the time of the purchase request, then Bonneville shall attempt to purchase, based on various factors as listed below in this section 5(e), up to 510 MW of *inc* balancing reserve capacity from third parties for imbalance service in the Spring Months and fund such purchases with the Annual Budget subject to section 6 below. In making such acquisitions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Spring Months.
6. **Annual Budget for the FY 2016-2017 rate period.**
- a. Bonneville shall establish a base \$17.5 million annual budget (“Annual Budget”) to fund the purposes set forth in section 6(b) below during the Rate Period. Any unspent funds from the FY 2016 Annual Budget will increase the FY 2017 Annual Budget for the purposes in this section 6. Any unspent funds in FY 2017 will remain with Transmission Services.
 - b. The Annual Budget is subject to adjustment as provided for in this Attachment 1. The FY 2017 Annual Budget is subject to reduction by the Mid-Rate Period Adjustment as described in section 8 and as described in section 16 below. Bonneville will use the Annual Budget to fund (1) the purchase of 10 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment) during the Non-Spring Months (see Section 4(b) above); (2) the cost of any *inc* balancing reserve capacity that Bonneville provides from the FCRPS above 400 MW during the Spring Months (see section 5(d) above); (3) purchases of *inc* balancing reserve capacity from third parties during the Spring Months; (4) any differences between the energy cost Bonneville incurs for deployment of third-party capacity and the hourly energy index price in the Pacific Northwest; and (5) replacement *inc* balancing reserve capacity Bonneville purchased from third parties under Sections 4(a)(1) and 5(a) of this Attachment 1.

Attachment 1 to the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement

- c. When the Annual Budget is exhausted, Bonneville shall treat any energy costs of third-party balancing reserve capacity deployment that exceed the hourly energy index price in the Pacific Northwest as a Transmission Services cost.
- d. Bonneville will post quarterly reports on its OASIS website describing: (1) the types and amounts of expenditures made in the previous quarter and the status of the Annual Budget; and (2) any instances during the previous quarter in which Bonneville committed to provide *inc* balancing reserve capacity from the FCRPS, as contemplated by Sections 4(a)(1) and 5(a) of this Attachment 1, and was subsequently unable to do so.
- e. The Annual Budget is subject to increase in an amount equivalent to the revenue received from the \$0.20/kW-nameplate/mo fee (section III.E.2.a.(4)(d) of the ACS-16 rate schedules in Attachment 2) paid by customers that elect to opt out of the Intentional Deviation Penalty Charge.
- f. If Bonneville anticipates or observes a total of 120 hours in which a curtailment event occurs due to lack of *inc* balancing reserve capacity in the Spring Months of FY 2016 before the expiration of such Spring Months or if Bonneville determines that it needs to spend additional funds above the Annual Budget for FY 2016 to support the *inc* imbalance service in FY 2016 Spring Months, Bonneville may use up to \$5 million of the FY 2017 Annual Budget to support the *inc* imbalance service provided during the FY 2016 Spring Months. In such event, Bonneville shall inform all parties of the issue(s) causing the decreased quality of imbalance service and will convene a stakeholder process to discuss approaches to provide the quality of imbalance service intended in this settlement for the FY 2017 Spring Months without violating any other terms and conditions of this settlement. Notwithstanding section 6(b) above, Bonneville will restore the FY 2017 Annual Budget by the amount of the FY 2017 Annual Budget used to support the *inc* imbalance service provided during the FY 2016 Spring Months, not to exceed \$5 million. Under this approach, Bonneville shall treat any increase to the Annual Budget as a transmission cost.
- g. To the extent Bonneville does not use all of the \$5 million described in section 6(f) above to restore the FY 2017 Annual Budget, Bonneville may use the remainder of those funds to supplement the FY 2017 Annual Budget if Bonneville anticipates or observes a total of 120 hours in which a curtailment event occurs due to lack of *inc* balancing reserve capacity in the Spring Months of FY 2017 before the expiration of such Spring Months or if Bonneville determines that it needs to spend additional funds above the Annual Budget for FY 2017 to support the *inc* imbalance service in FY 2017 Spring Months. In such event, Bonneville shall inform all parties of the issue(s) causing the decreased quality of imbalance service and will convene a stakeholder process to discuss approaches to provide the quality of imbalance service intended in this settlement for the remaining FY 2017 Spring Months without violating any other terms and conditions of this settlement. Bonneville shall treat any increase to the Annual Budget described in this section 6(g) as a transmission cost.
- h. If the Annual Budget is exhausted in either fiscal year of the Rate Period, Bonneville will not be obligated to purchase any additional *inc* balancing reserve capacity in the fiscal year, except as

described in Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2.

- i. Nothing in this Agreement is intended to limit Bonneville’s right to purchase additional balancing reserve capacity for system reliability purposes.

7. Mid-Rate Period Election.

- a. Bonneville will offer VERBS customers a mid-Rate Period election opportunity to change their scheduling elections to a superior scheduling commitment, elect self-supply, use Dynamic Transfer Capability (“DTC”) to transfer out of Bonneville’s balancing authority area (subject to implementation of necessary arrangements, which shall not be unreasonably delayed), or elect to participate in Customer Supplied Generation Imbalance (“CSGI”). VERBS customers that elect self-supply, use of DTC to transfer out of Bonneville’s balancing authority area, or CSGI must provide Bonneville with written notice to change service by close of business on April 4, 2016, and the effective date of the election change will be October 1, 2016. Customers that elect to change their scheduling election to a superior scheduling commitment must provide Bonneville with written notice to change service by close of business on June 1, 2016, and the effective date of the election change will be October 1, 2016.
- b. The election changes in 7(a) above will be capped at 800 MW of nameplate movement offered on a first-come first-served basis. The expansion of self-supply, including the CSGI program, and DTC will be limited to a total of 300 MW and will count toward the 800 MW cap on nameplate movement. Bonneville will use two adjustments to calculate the nameplate movement equivalent when a customer switches from CSGI to either (1) self-supply in accordance with Bonneville’s self-supply Business Practice, as revised, or (2) use DTC to transfer out of Bonneville’s balancing authority area. The amount of nameplate that switches from CSGI will be multiplied by 21% for purposes of calculating the impact on the 300 MW cap on nameplate movement. The amount of nameplate that switches from CSGI will be multiplied by 53% for purposes of calculating the impact on the 800 MW cap on nameplate movement and amount of nameplate that changed elections as used in section 8 below. Customers will pay the posted rates associated with their revised election choice.

- 8. **Mid-Rate Period Adjustment.** The Mid-Rate Period Adjustment (“Mid-Rate Period Adjustment” or “MidRPAdjustment”) will apply to the second year of the Rate Period. The Mid-Rate Period Adjustment will adjust the amount of *inc* balancing reserve capacity Bonneville will provide in the Non-Spring Months in FY 2017 and the FY 2017 Annual Budget. Bonneville shall calculate the Mid-Rate Period Adjustment using the ratio of nameplate that changed elections (“Nameplate Movement”) to the total amount of allowable nameplate movement (800 MW) under section 7 above. The Mid-Rate Period Adjustment will equal:

$$MidRPAdjustment = \frac{Nameplate\ Movement}{800\ MW}$$

- a. The Mid-Rate Period Adjustment may reduce the 910 MW of *inc* balancing reserve capacity requirement described in section 4, *Inc Reserve (Non-Spring Months)*, above. The second year amount will equal:

$$910 \text{ MW} - [10 \text{ MW} \times \text{MidRPAdjustment}]$$

- b. The Mid-Rate Period Adjustment may reduce the FY 2017 Annual Budget. The FY 2017 Annual Budget will equal:

$$\$17.5 \text{ million} - [\$900,000 \times \text{MidRPAdjustment}]$$

9. **Scheduling Elections.** Bonneville shall offer VERBS customers a mid-Rate Period election opportunity to change their scheduling elections from a sub-hourly scheduling commitment (30/15 or 40/15) to a 30/60 committed scheduling election, which will not be subject to the Direct Assignment Charges as described in Section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2. These election changes will be capped at 800 MW of nameplate movement offered on a first-come first-serve basis. VERBS customers must provide Bonneville with written notice to change service by close of business on April 4, 2016, and the effective date of the election change will be October 1, 2016. Customers will pay the posted rates associated with their revised election choice.
10. **Operating Practices.**
 - a. Bonneville shall replace Dispatcher Standing Order No. 216 with a reliability tool that applies to all non-Federal non-controlling generation—both dispatchable and variable energy resources—in Bonneville’s Balancing Authority Area, except the schedule curtailment protocol will not apply to behind-the-meter generation. Bonneville will design the new reliability tool to attempt to equitably allocate curtailments among all resources that are subject to the reliability tool. Bonneville shall use reasonable efforts to provide a mechanism for multiple resources to combine their Station Control Error to take advantage of diversity benefits during balancing reserve capacity-related events. Bonneville shall not apply its automated balancing reserve capacity-related generation limitation protocol to dispatchable energy resources.
 - b. Bonneville shall research potential impacts that Federal dispatchable resources have on Bonneville’s Balancing Authority Area net Station Control Error during *inc* reliability events and provide results to customers in spring 2015. Any material impacts discovered will be mitigated through changes in internal Bonneville business practices or modifications to implementation of balancing reserve capacity-related schedule curtailments of dispatchable and variable energy resources.
 - c. Bonneville shall conduct a stakeholder process through the Joint Operating Committee or other public forum to discuss Bonneville’s proposed reliability tool and provide an opportunity for customers to comment on the reliability tool.
11. **Intentional Deviation.** One Hundred Percent (100%) of the revenue that Bonneville receives through the Intentional Deviation Charge shall remain with Transmission Services. Revenue that Bonneville receives from Energy Imbalance (“Elev”), Generation Imbalance (“Glev”), and Persistent Deviation

Attachment 1 to the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement

(“PDrev”) will be split between Power Services and Transmission Services. Power Services’ share (“PSshare”) in such revenue will equal:

$$PSshare = [EIrev + GIrev + PDrev] - \sum Hr3PSD \times HrIndex$$

Where:

Hr3PSD = The MWh amount of third-party *inc* balancing reserve capacity deployed each hour.

HrIndex = The hourly energy index in the Pacific Northwest during the hour when the third-party *inc* balancing reserve capacity was deployed.

12. **Revenue Credit.** Power Services will receive a payment of at least \$50,834,800 each year of the Rate Period from Transmission Services in exchange for planned balancing reserve capacity provided from the FCRPS as described in sections 3, 4 and 5 above. Power Services will set power rates with the revenue credit expectation that it will receive \$54,834,800 from Transmission Services. This section 12 is subject to section 16(b) below.
13. **Rate Period Initiative.**
 - a. Bonneville and customers will establish a Solar Task Force to discuss transmission and integration issues related to solar energy development in Bonneville’s Balancing Authority Area, including the discussion of customer proposals on Solar VERBS rate design.
 - b. Bonneville shall hold a workshop in October of 2014 to discuss with customers the potential for an acquisition strategy for the Spring Months that includes long-term purchases of *inc* balancing reserve capacity that are 6 to 9 months in advance of the Spring Months.
14. **Other charges.** Pursuant to the conditions under Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2, Bonneville will use the following table to assess the additional amount of *inc* balancing reserve capacity.

From Service in Row to Service in Column	<u>Direct Assignment Charges. Additional Amount of Inc Capacity on Nameplate</u>						
	30/15	40/15	30/60	Uncommitted	Solar	DERBS	CSGI
30/15	N/A	2.5%	5.2%	8.1%	N/A	N/A	N/A
40/15	N/A	N/A	2.7%	5.6%	N/A	N/A	N/A
30/60	N/A	N/A	N/A	2.9%	N/A	N/A	N/A
CSGI	3.3%	5.8%	8.5%	11.4%	N/A	N/A	N/A
No Service	8.3%	10.8%	13.5%	16.4%	2.4%	0.5%	5.0 %

15. **Inter-Business Line Allocations.** Bonneville and Assenting Parties agree to the Inter-Business Line Allocations described in Attachment 3.

16. **Risk Mitigation Tools.**

a. **CRAC, DDC, and NFB Mechanisms.** 8.2 percent of the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) will apply to the balancing reserve capacity-based rates specified in Section II.H of the General Rate Schedule Provisions in Attachment 2.

b. **Planned Net Revenues for Risk.** The rates under this Agreement are based on the assumption that Bonneville’s power revenue requirement will not contain Planned Net Revenues for Risk or any risk mitigation tool that: (1) supports Bonneville’s power Treasury Payment Probability; (2) supports Bonneville’s credit rating; or (3) enhances Bonneville’s financial strength or financial standing by improving Bonneville’s cash position (“Risk Mitigation Tool” or “RMT”). If Bonneville adopts any RMT in its overall power revenue requirement as determined in the BP-16 Final Proposal, then the following will apply:

(i) The Annual Budget will decrease by 4.27% multiplied by the RMT.

(ii) Notwithstanding section 12 above, Power Services will receive a payment of at least $\$50,834,800 + [8.2\% \times RMT]$ each year of the Rate Period from Transmission Services in exchange for planned balancing reserve capacity provided from the FCRPS as described in sections 3, 4 and 5 above. Power Services will set power rates with the revenue credit expectation that it will receive $\$54,834,800 + [8.2\% \times RMT]$ from Transmission Services.

(iii) The ancillary and control area service rates in Attachment 2, ACS-16, sections II and III, will increase to collect each rate’s percentage share of the $[8.2\% \times RMT]$ amount based on the following table:

Rates	Percent Share of RMT
Regulating and Frequency Response Service	0.46%
Dispatchable Energy Resource Balancing Service (DERBS) <i>Inc</i>	0.09%
DERBS <i>Dec</i>	0.09%
Operating Reserve - Spinning	1.65%
Operating Reserve – Spinning default	Function of Operating Reserves Spinning (115%)
Operating Reserve - Supplemental	1.65%
Operating Reserve – Supplemental default	Function of Operating Reserves Supplemental (115%)

17. **Official Forecast.** Bonneville will attempt to provide the results of the Super Forecast Methodology to

Attachment 1 to the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement

customers at 15 minutes or earlier after the top of the hour, but will commit to provide the results of the Super Forecast Methodology to customers no later than 20 minutes after the top of the hour.

[This space intentionally left blank]

ACS-1416
ANCILLARY AND CONTROL AREA SERVICES RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-~~12-14~~ rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

SECTION II. ANCILLARY SERVICE RATES

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest~~same basis as the intra-hour~~ scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW,

whichever is larger in absolute value, up to and including
 (i) ± 7.5 percent of the scheduled amount of energy or
 (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.
- (2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation ([GRSP III.42](#)):

- (1) No credit is given when energy taken is less than the scheduled energy.
- (2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-~~14~~16 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but

not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer’s Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA, the rate shall not exceed ~~11.40~~10.86 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~13.11~~12.49 mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer’s Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014–2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserve Requirement posted on its OASIS Web site accordingly.~~
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service ~~Transmission Services from BPA~~, the rate shall not exceed ~~10.459.95~~ mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~12.0244.44~~ mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer’s Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014–2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserve Requirement posted on its OASIS Web site accordingly.~~

- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES**A. REGULATION AND FREQUENCY RESPONSE SERVICE**

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest~~on the same basis as the intra-hour~~ scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including

(i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.I.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section ~~III.B.1.~~ of this ACS-~~1614~~ Generation Imbalance Service rate schedule.

~~Customers participating in committed scheduling to receive (i) BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling), each 30-minute schedule period (30/30 committed scheduling), or each 60-minute schedule period (30/60 committed scheduling), or (ii) BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling), and that submit schedules that are consistent with or result in less imbalance for the committed scheduled period are exempt from the Persistent Deviation penalty charge.~~

For Variable Energy Resources (wind and solar resources), BPA will remove specific scheduled periods for billing purposes from a persistent deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

d. No Credit for Negative Deviations During Curtailments

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the shortest scheduling period available for committed scheduling the ACS-16 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and (3).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

- (1) wind resources
- (2) solar resources
- (3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the [Transmission Control Area Service](#) Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed ~~11.40~~^{10.86} mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~13.11~~^{12.49} mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable [NERC](#), WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014–2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserves Requirement posted on its OASIS Web site accordingly.~~
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the [Transmission Control Area Service](#) Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed [10.459.95](#) mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be [12.0244.44](#) mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable [NERC](#), WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014–2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserves Requirement posted on its OASIS Web site accordingly.~~
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c. of this rate schedule.

Variable Energy Resource Balancing Service (“VERBS” or “Balancing Service”) ~~Base Service (“Base Service”)~~ is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator’s schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

~~**Variable Energy Resource Balancing Service Full Service (“Full Service”)** is an optional quarterly service except as provided in section 2.c.3. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Under this Full Service option, the amount of balancing reserve capacity available to the customer under a committed scheduling Base Service option is augmented through BPA purchases of additional balancing reserve capacity.~~

~~**Variable Energy Resource Balancing Service Supplemental Service (“Supplemental Service”)** is an optional monthly service. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Purchase of this Supplemental Service augments balancing reserve capacity available to the Customer to mitigate the effects of DSO-216 curtailments on variable energy resource schedules.~~

2. BALANCING~~BASE~~ SERVICE FOR WIND RESOURCES

The total charge for Balancing~~Base~~ Service is the applicable Base~~Service~~ rate in section 2.a., below, plus ~~Purchases-Charges for~~ Direct Assignment Charges under section 4~~6~~ and Intentional Deviation Penalty Charges under section 5.

a. BALANCING ~~BASE~~-SERVICE RATES

(1) Rate for 30/60 Committed Scheduling

This rate is applicable to customers taking Balancing~~Base~~ Service that commit to receive BPA's 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.80 per kilowatt per month

(2) Rate for 40/15 Committed Scheduling

This rate is applicable to customers taking Balancing~~Base~~ Service that commit to receive BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.54 per kilowatt per month

~~(3) Rate for 30/30 Committed Scheduling~~

~~This rate is applicable to customers taking Base Service that commit to receive BPA's 30-minute signal for each 30-minute schedule period (30/30 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.~~

- ~~(a) Regulating Reserves \$0.08 per kilowatt per month~~
- ~~(b) Following Reserves \$0.32 per kilowatt per month~~
- ~~(c) Imbalance Reserves \$0.47 per kilowatt per month~~

(43) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing ~~Base~~ Service that commit to receive BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.33 per kilowatt per month

(54) Rate for Uncommitted Scheduling

This rate is applicable to customers taking ~~Base~~ Balancing Service that do not commit to 30/60, 30/40/60-15 or 30/30-15 scheduling ("uncommitted scheduling").

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$1.08 per kilowatt per month

(d) Opt Out Fee

The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.I) shall be \$0.20 per kilowatt per month.

b. BILLING FACTOR

The Billing Factor for rates in section 2.a. is as follows:

- (1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.
- (2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.

- (3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

- (1) The rates under section 2.a. above will not apply to a ~~V~~variable ~~E~~energy ~~R~~resource, or portion of a ~~V~~variable ~~E~~energy ~~R~~resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.
- (2) Individual rate components under section 2.a.(1)-(5) above will not apply to a ~~V~~variable ~~E~~energy ~~R~~resource, or portion of a ~~V~~variable ~~E~~energy ~~R~~resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of ~~b~~Balancing ~~s~~Service, including by contractual arrangements for third-party supply.
- ~~(3) — Application of Full Service charge to all Base Service Customers: If because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially, except as provided in sections 2.c. and 5 of this rate schedule, all Base Service customers shall pay the total Full Service charge in accordance with section 3 below.~~

~~3. FULL SERVICE FOR WIND RESOURCES~~~~The total charge for Full Service is:~~

- ~~a. the applicable Base Service rate in section 2.a.(1), 2.a.(2), 2.a.(3), or 2.a.(4) plus any Purchases Charges for Direct Assignment; plus~~
- ~~b. Purchases Charges for Full Service under section 6.~~

43. VARIABLE ENERGY RESOURCE-BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate below, plus Direct Assignment ~~Purchases~~ Charges under section ~~64~~ and Intentional Deviation Penalty Charges under section 5.

a. RATES

- | | | |
|-----|---------------------|-------------------------------|
| (1) | Regulating Reserves | \$0.04 per kilowatt per month |
| (2) | Following Reserves | \$0.17 per kilowatt per month |

b. BILLING FACTOR

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

c. EXCEPTIONS

See section 2.c. above.

~~5. SUPPLEMENTAL SERVICE~~~~a. RATES~~~~The monthly Supplemental Service rate in \$/MW shall equal:~~~~$$\frac{\text{Purchase Cost}}{\text{Imbalance Reserve}}$$~~~~Where:~~

~~Purchase Cost = The sum of all purchase costs incurred by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in dollars (\$).~~

~~Imbalance Reserve = The sum of all imbalance reserves purchased by BPA to supply Supplemental Service for the relevant month or months for customers that commit to take such service, in MW months.~~

~~b. BILLING FACTOR~~

~~The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase.~~

~~c. EXCEPTIONS~~

~~None.~~

64. DIRECT ASSIGNMENT ~~FORMULA PURCHASES CHARGES~~

~~These charges will recover the cost of *inc* balancing reserve capacity purchases.~~

~~(1) Purchases Charge for Purchases of Balancing Reserve Capacity to Support Full Service~~

~~BPA will apply the Purchases Charge for Full Service to customers taking Full Service if BPA purchases balancing reserve capacity beyond the level of balancing reserve capacity that is made available under a committed scheduling Base Service election to meet the increased balancing reserve capacity requirements of Full Service customers.~~

~~**Purchases Charge for Full Service:**~~

~~For each Full Service customer, the monthly charge for Full Service Purchases shall be:~~

$$\text{Full Svc \$} = (\text{Aug Cost} / \text{Svc BF}) * \text{Billing Factor}$$

~~Where:~~

~~Full Service \$ = The monthly charge for each Full Service customer for purchases of balancing reserve capacity to support the Full Service option, in \$.~~

~~Aug Cost = The total costs associated with acquiring balancing reserve capacity to augment the balancing capacity needs of Full Service customers, in \$/mo.~~

~~Svc BF = ————— The sum of the billing factors, as identified in section 2.b., for the month for which the balancing reserve capacity was purchased for Variable Energy Resources that take Full Service, in kilowatts.~~

~~Billing Factor = ————— The Variable Energy Resource billing factor, as identified in section 2.b. for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

~~**a.(12) Purchases Charge for Direct Assignment of Costs to a Customer**~~

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

- ~~(a)a.~~ the customer elected to self-supply in accordance with section 2.c. but is unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or
- ~~(b)b.~~ the customer has a projected generator interconnection date after FY 201~~75~~, but chooses to interconnect during the FY 201~~64~~–201~~75~~ rate period; or
- ~~(c)c.~~ the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3), ~~or 2.a.(4)~~ above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or
- ~~(d)d.~~ the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3), ~~or 2.a.(4)~~ above, but chooses to take a Base Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or
- e. the customer either elected to dynamically transfer its resource out of BPA's Balancing Authority Area or has successfully dynamically transferred its resource out of BPA's Balancing Authority Area, but chooses to keep its resource in BPA's Balancing Authority Area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct

assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.I.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all ~~non-Federal~~ Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section ~~III.F.3~~ below. Dispatchable Energy Resource Balancing Service (“DERBS”) is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge determined by applying the~~for the~~ applicable rates in section 1 below, plus ~~Purchases Charges for~~ Direct Assignment Charges in section 4 below.

1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

- a. Incremental Reserves = 18.15 mills per kW maximum hourly deviation
- b. Decremental Reserves = 3.94 mills per kW maximum hourly deviation

2. BILLING FACTORS

- a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative Sstation eControl Error (under-generation), including ramp periods, that exceeds 3 MW for that hour.
- b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive sStation Control eError (over-generation), including ramp periods, that exceeds 3 MW for that hour.

3. EXCEPTIONS

- a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA’s Balancing Authority Area to another Balancing Authority Area.
- b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

- c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.
- d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

4. DIRECT ASSIGNMENT CHARGES

a. ~~Purchases Charge for Full Service~~

~~Not applicable.~~

ab. ~~Purchases Charge for Direct Assignment of Costs to a Customer~~

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

- ~~(1)~~a. the ~~C~~customer elected to self-supply but is unable to ~~continue~~ self-supplying the Dispatchable Energy Resource Balancing Service; or
- ~~(2)~~b. a ~~C~~customer has a projected generator interconnection date after FY 201~~7~~5 but chooses to interconnect during the FY 201~~6~~4-201~~7~~5 rate period; ~~or~~
- ~~(3)~~c. a ~~C~~customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 201~~6~~4-201~~7~~5 rate period; or
- d. the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.D.

**B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES
ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS**

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in GRSP II.H.

GENERAL RATE SCHEDULE PROVISIONS

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

H. CRAC, DDC, AND NFB MECHANISMS

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.C, II.E, and II.N.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service
- Variable Energy Resource Balancing Service (VERBS)

Exception: For the VERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under [section III.E.2.a.\(4\), opt out fee](#), [section III.E.64., Direct Assignment Formula Purchases](#), [Charges and Intentional Deviation](#), [GRSP II.I.](#)

- Dispatchable Energy Resource Balancing Service (DERBS)

Exception: For the DERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under [section III.F.4., Direct Assignment Formula Purchases](#), [Charges and Intentional Deviation](#), [GRSP II.I.](#)

1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

2. CUSTOMER CREDIT FOR THE ACS DDC

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed from the ACS rates specified above; the balance of the DDC Amount is to be distributed from specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

The CRAC, DDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.C, II.E, and II.N, are incorporated by reference.

I. INTENTIONAL DEVIATION PENALTY CHARGE

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-16 Variable Energy Resources Balancing Service rate.

Exceptions:

- a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS-16 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for Generation penalty charge as specified in the ACS-16 Generation Imbalance Service rate schedule (section III.B.2.c).
- b. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.
- c. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be \$100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

$$\frac{\text{ABS(Intentional Deviation Measurement Value – Resource Schedule)}}{\geq 1}$$

(See section 3, below, for definition of terms.)

3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule)
– 1

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following three values:

- 1) for wind generating customers taking VERBS at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3)), the applicable committed schedule value provided by BPA;
- 2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40-minute forecast schedule value produced by the Super Forecast Methodology; or
- 3) for solar generating customers taking VERBS (section 3), the matrix forecast schedule value or applicable committed schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

$$\underline{\text{ABS(Station Control Error)} \leq \text{ABS(Intentional Deviation Measurement Value Error)} + 1 \text{ MW}}$$

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

GRSP SECTION III. DEFINITIONS

(Note: Numbering of definitions may change for final rate proposal.)

1. ANCILLARY SERVICES

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

- a. Scheduling, System Control, and Dispatch
- b. Reactive Supply and Voltage Control from Generation Sources
- c. Regulation and Frequency Response
- d. Energy Imbalance
- e. Operating Reserve – Spinning
- f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. BALANCING AUTHORITY AREA

See definition in Control Area.

4. CONTROL AREA

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
- b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all

of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

- a. Regulation and Frequency Response Service
- b. Generation Imbalance Service
- c. Operating Reserve – Spinning Reserve Service
- d. Operating Reserve – Supplemental Reserve Service
- e. Variable Energy Resource Balancing Service
- f. Dispatchable Energy Resource Balancing Service

9. DISPATCHABLE ENERGY RESOURCE

For purposes of ~~the ACS rate schedule~~~~Dispatchable Energy Resource Balancing Service~~, a Dispatchable Energy Resource is any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

10. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

11. DYNAMIC SCHEDULE

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. DYNAMIC TRANSFER

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

14. ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in

the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

17. GENERATION IMBALANCE

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

18. GENERATION IMBALANCE SERVICE

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

39. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission [Customer](#) or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission [Customer's](#) or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission [Customer](#) or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's [or Control Area Service Customer's](#) obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. OPERATING RESERVE REQUIREMENT

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, “Contingency Reserve Sharing Procedure,” and WECC Standards.

42. PERSISTENT DEVIATION

A Persistent Deviation event is one or more of the following:

a. For Generation Imbalance Service only:

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction;
or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. For Energy Imbalance Service only:

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction;
or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

- c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

50. REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

62. SPILL CONDITION

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

63. SPINNING RESERVE REQUIREMENT

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

64. STATION CONTROL ERROR

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

65. SUPER FORECAST METHODOLOGY

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. SUPPLEMENTAL RESERVE REQUIREMENT

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

72. VARIABLE ENERGY RESOURCE

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

73. VARIABLE ENERGY RESOURCE BALANCING SERVICE

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

Attachment 3 Inter-Business Line Allocations					
	A	B	C	D	E
	Generation Inputs	Rate or Cost	Unit	Annual Average for FY 2016-2017 Forecast Quantity	Annual Average for FY 2016-2017 Revenue Forecast
1	Regulating Reserve	0.12	mills/kWh/month	5,921	\$ 6,224,155
2	Variable Energy Resource Balancing Service Reserve - 30/60 Committed Scheduling	\$ 1.20	\$/kW/month	556	\$ 8,006,400
3	Variable Energy Resource Balancing Service Reserve - 40/15 Committed Scheduling	\$ 0.94	\$/kW/month	-	\$ -
4	Variable Energy Resource Balancing Service Reserve - 30/15 Committed Scheduling	\$ 0.73	\$/kW/month	762	\$ 6,675,120
5	Variable Energy Resource Balancing Service Reserve - Uncommitted Scheduling	\$ 1.48	\$/kW/month	2,100	\$ 37,296,000
6	Variable Energy Resource Balancing Service Reserve - Self-Supply of Generation Imbalance	\$ 0.40	\$/kW/month	1,390	\$ 6,672,000
7	Variable Energy Resource Balancing Service for Solar	\$ 0.21	\$/kW/month	34	\$ 85,680
8	Dispatchable Energy Resource Balancing Service Reserve <i>inc</i>	18.15	mills/kWh/month	113,439	\$ 2,058,918
9	Dispatchable Energy Resource Balancing Service Reserve <i>dec</i>	3.94	mills/kWh/month	99,133	\$ 390,584
10	Dispatchable Energy Resource Balancing Service Reserve Total				\$ 2,449,502
11	Settlement Annual Budget Adjustment				\$ (15,200,000)
12	Rounding Adjustment				\$ 25,943
13	Adjustment for Settlement for Supplying Only 900 MW <i>dec</i> Balancing Reserve Capacity				\$ (1,400,000)
14	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned				\$ 4,000,000
15	Operating Reserve - Spinning	11.40	mills/kWh/month	255.1	\$ 25,470,313
16	Operating Reserve - Supplemental	10.45	mills/kWh/month	255.1	\$ 23,347,787
17	Operating Reserve Total			510.1	\$ 48,818,100
18	Synchronous Condensing				\$ 1,610,466
19	Generation Dropping				\$ 415,417
20	Redispatch				\$ 225,000
21	Segmentation of COE/Reclamation Network and Delivery Facilities				\$ 7,367,000
22	Station Service				\$ 2,479,123
23	Generation Inputs Total				\$ 115,749,907

BP-16 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix B: Power Rate Schedules
and General Rate Schedule Provisions

BP-16-A-02-AP02

July 2015



BONNEVILLE POWER ADMINISTRATION

POWER RATE SCHEDULES

TABLE OF CONTENTS

	<u>Page</u>
COMMONLY USED ACRONYMS AND SHORT FORMS	iii
POWER RATE SCHEDULES	1
PF-16 Priority Firm Power Rate	5
NR-16 New Resource Firm Power Rate	19
IP-16 Industrial Firm Power Rate	23
FPS-16 Firm Power and Surplus Products and Services Rate	27
GENERAL RATE SCHEDULE PROVISIONS	35
I. ADOPTION OF REVISED POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS	35
A. Approval of Rates	35
B. General Provisions	35
C. Payment Provisions	35
D. Notices	36
E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements	36
F. Metering Usage Data Estimation Provision	38
II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS	39
A. Conservation	39
B. Cost Contributions	39
C. Cost Recovery Adjustment Clause (CRAC)	40
D. Demand Rate Billing Determinant Adjustments	45
E. Dividend Distribution Clause (DDC)	47
F. DSI Reserves	50
G. NR Services for New Large Single Loads (NLSL)	51
H. Flexible New Resource Firm Power (NR) Rate Option	54
I. Flexible Priority Firm Power (PF) Rate Option	55
J. General Transfer Agreement Service Charges	55
K. Irrigation Rate Discount	57
L. Load Shaping Charge True-Up Adjustment	59
M. Low Density Discount (LDD)	61
N. NFB Mechanisms	66
O. [Reserved for future use]	73
P. Priority Firm Power (PF) Shaping Option	73

Q.	Priority Firm Power (PF) Tier 1 Equivalent Rates	74
R.	Remarketing.....	75
S.	Residential Exchange Program Residential Load.....	76
T.	Residential Exchange Program 7(b)(3) Surcharge Adjustment.....	77
U.	Resource Support Services and Transmission Scheduling Service	79
V.	RHWM Tier 1 System Capability (RT1SC).....	88
W.	Slice True-Up Adjustment	88
X.	Tier 2 Rate TCMS Adjustment	94
Y.	TOCA Adjustment.....	94
Z.	Unanticipated Load Service.....	95
AA.	Unauthorized Increase (UAI) Charge	100
III.	DEFINITIONS.....	103
A.	Power Products and Services Offered By BPA Power Services	103
B.	Definition of Rate Schedule Terms.....	106

Appendices

Appendix A.	REP Settlement Customer Refund Amounts in FY 2016–2017	115
Appendix B.	Tier 2 Load Growth Rate Customer Charge for FY 2016–2017.....	121
Appendix C.	Slice Billing Adjustment	125

COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMP	Oversupply Management Protocol
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability
PF	Priority Firm Power
PFIA	Projects Funded in Advance
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
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)
RD	Regional Dialogue
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 rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

POWER RATE SCHEDULES

This page intentionally left blank.

POWER RATE SCHEDULES

INDEX

	<u>Page</u>
PF-16 Priority Firm Power Rate.....	5
1 Availability	5
2 Priority Firm Public Rate	5
3 Priority Firm Melded Rate	12
4 Unanticipated Load Rate.....	14
5 Resource Support Services Rates.....	14
6 Priority Firm Exchange Rate	15
7 Adjustments, Charges, and Special Rate Provisions	16
NR-16 New Resource Firm Power Rate	19
1 Availability	19
2 New Resource Rates	19
3 Unanticipated Load Rate.....	20
4 Energy Shaping Service for New Large Single Load (NLSL) Charge.....	20
5 NR Resource Flattening Service Charge	21
6 Adjustments, Charges, and Special Rate Provisions	21
IP-16 Industrial Firm Power Rate	23
1 Availability	23
2 Industrial Firm Rates.....	23
3 Adjustments, Charges, and Special Rate Provisions	25
FPS-16 Firm Power and Surplus Products and Services Rate	27
1 Availability	27
2 Firm Power and Capacity Without Energy.....	27
3 Shaping Services.....	27
4 Reservations and Rights to Change Services.....	28
5 Reassignment or Remarketing of Surplus Transmission Capacity.....	28
6 Services for Non-Federal Resources.....	28
7 Unanticipated Load Service.....	29
8 Other Capacity, Energy, and Scheduling Products and Services.....	29
9 Adjustments, Charges, and Special Rate Provisions	29

This page intentionally left blank.

SCHEDULE PF-16

PRIORITY FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of Firm Requirements Power pursuant to section 5(b) of the Northwest Power Act. Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test, and Start-Up, and Station Service.

Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Residential Exchange Program Power pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the PF-14 rate schedule. Sales under the PF-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer include two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to Customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice, and Slice Customer rates are specified in the following table:

<i>Customer Charge Rate in dollars per percentage point of billing determinant</i>			
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Customer Rate	2,062,767	(306,652)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer billing determinants are specified in the following table:

<i>Customer Charge Billing determinant for each rate</i>			
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percentage

For each Customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\text{Minimum of the Customer's:}}{\text{Sum of all Customers' RHWMs}} \times 100$$

a) RHWM, or
b) Forecast Net Requirement for each Fiscal Year

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All Customer TOCAs shall be posted on the BPA Web site. A Customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.Y.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice Customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percentage.

A Customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.Y.

2.1.2 Demand Charge

The Demand Charge is applicable to Customers that purchase the following products: Load Following and Block with Shaping.

2.1.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

$$\textit{Tier 1 CSP} - a\textit{HLH} - \textit{CDQ} - \textit{SuperPeak}$$

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the Customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts

HLH = Average of the Customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the Customer's CHWM Contract, Exhibit B, section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the Customer's CHWM Contract, Exhibit A, section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

The Demand billing determinant may be adjusted pursuant to GRSP II.D.

If a Customer purchases Secondary Crediting Service, the Demand billing determinant may be adjusted pursuant to GRSP II.U.2.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to Customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or LLH), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	\$27.86	\$23.75
November	\$28.56	\$24.48
December	\$29.22	\$24.82
January	\$30.02	\$25.03
February	\$29.65	\$24.68
March	\$25.38	\$22.07
April	\$24.36	\$21.04
May	\$22.10	\$17.53
June	\$23.15	\$17.11
July	\$27.43	\$21.58
August	\$30.30	\$24.41
September	\$31.75	\$25.70

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

$$\begin{aligned} & \text{Customer's Actual Monthly/Diurnal Tier 1 Load,} \\ & \text{in kilowatthours} \\ & \textit{Minus} \\ & \text{Customer's System Shaped Load for the relevant diurnal period,} \\ & \text{in kilowatthours} \end{aligned}$$

If a Customer purchases Secondary Crediting Service (SCS), the Load Shaping billing determinant may be adjusted pursuant to GRSP II.U.2.

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The Customer's System Shaped Load for each diurnal period equals:

$$RTISC \times TOCA$$

Where:

RTISC = RHWMTier 1 System Capability for the relevant diurnal period, in kilowatthours. The *RTISC* for each diurnal period of the Rate Period is specified in GRSP II.V.

TOCA = The effective TOCA for a Load Following or Block Customer, or the effective Non-Slice TOCA for a Slice/Block Customer, expressed as a percentage. The TOCA used in this System Shaped Load calculation shall reflect a Customer's Adjusted TOCA pursuant to GRSP II.Y.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a JOE, the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.1.4 Slice Billing Adjustment

Customers that purchased the Slice Product during the period FY 2012–2015 are subject to a billing adjustment in FY 2016.

The billing adjustment shall appear on the Customer's November 2015 power bill.

The adjustment amount for each Customer is set forth in Appendix C to the General Rate Schedule Provisions.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to section 4.3 of the Tiered Rate Methodology, BP-12-A-03, the Tier 2 Load Shaping charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates

The Tier 2 Load Shaping Rates shall be the rates specified in section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant

The Tier 2 Load Shaping billing determinant for each billing period is incorporated into the billing determinant established in section 2.1.3.2.

2.2.2 Short-Term Charge

The Short-Term Charge is applicable to Customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.2.1 Short-Term Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	29.72
2017	32.01

2.2.2.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3 Load Growth Charge

The Load Growth Charge is applicable to Customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.3.1 Load Growth Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	45.18
2017	49.60

2.2.3.2 Load Growth Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3.3 Load Growth Rate Customer Charge

Load Growth Rate Customers are subject to a customer charge for FY 2016 and FY 2017.

The monthly amounts charged to each Customer are set forth in Appendix B to the General Rate Schedule Provisions.

2.2.4 VR1-2014 Charge

The VR1-2014 Charge is applicable to Customers that elected to purchase power at the Tier 2 VR1-2014 Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.4.1 VR1-2014 Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	44.72
2017	49.08

2.2.4.2 VR1-2014 Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.5 VR1-2016 Charge

The VR1-2016 Charge is applicable to Customers that have elected to purchase power at the Tier 2 VR1-2016 Rate, as specified in the Customers' CHWM Contracts, Exhibit C, section 2.5.2.

2.2.5.1 VR1-2016 Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	40.60
2017	43.18

2.2.5.2 VR1-2016 Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3 Priority Firm Melded Rate

The PF Melded rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Melded rate is not available to loads that are considered unanticipated loads as defined in Unanticipated Load Service, GRSP II.Z.1.

3.1 Energy Charge

3.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	36.47	32.36
November	37.17	33.09
December	37.83	33.43
January	38.63	33.64
February	38.26	33.29
March	33.99	30.68
April	32.97	29.65
May	30.71	26.14
June	31.76	25.72
July	36.04	30.19
August	38.91	33.02
September	40.36	34.31

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the Customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the Customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4 Unanticipated Load Service Charge

The Unanticipated Load Service charge is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in Unanticipated Load Service, GRSP II.Z.2.

5 Resource Support Services Rates

Resource Support Services rates are applicable to Customers that elect to take Diurnal Flattening Service, Secondary Crediting Service, or Grandfathered Generation Management Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to Customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contracts.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges, specified in GRSP II.U.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources, other than small non-dispatchable resources, are subject to the Resource Shaping Charge and Adjustment, specified in GRSP II.U.1.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge, specified in GRSP II.U.2.

5.4 Grandfathered Generation Management Service (GMS)

Load Following Customers dedicating the entire output of an Existing Resource that received GMS under Subscription to their Tier 1 Load are subject to a GMS Reservation Fee, specified in GRSP II.U.5.

6 Priority Firm Exchange Rate

The PF Exchange rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange rate plus a utility-specific 7(b)(3) Surcharge. For consumer-owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange rate plus a utility-specific 7(b)(3) Surcharge.

<i>Investor-Owned Utilities</i>	<i>Rates in mills/kWh</i>		
	<i>Base PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Avista	47.95	2.60	50.54820
Idaho Power	47.95	9.56	57.51170
NorthWestern	47.95	21.05	68.99820
PacifiCorp	47.95	21.26	69.20550
Portland General	47.95	16.00	63.95300
Puget Sound Energy	47.95	13.21	61.15820
<i>Consumer-Owned Utilities</i>	<i>Base Tier 1 PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Clark Public Utilities	47.98	1.87	49.85
Snohomish County PUD No 1	47.98	1.01	48.99

6.1.1 7(b)(3) Surcharge for Non-Listed Utilities

For eligible Customers not listed in section 6.1, the applicable 7(b)(3) Surcharge shall equal the Customer's Average System Cost minus the applicable Base PF Exchange rate. The Customer's Average System Cost shall be determined pursuant to BPA's 2008 Average System Cost Methodology.

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the Customer's Residential Load specified in GRSP I.I.S., Table E.

7 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable to PF rates as shown in the following tables.

GRSP II.	Adjustments, Charges, and Special Rate Provisions	Applicable to:				REP
		Firm Requirements				
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block		
A.1	Conservation Surcharge	X	X	X		
A.2	Large Project Targeted Adjustment Charge	X	X	X		
B	Cost Contributions	X	X			
C	Cost Recovery Adjustment Clause (CRAC)	X	X			
D	Demand Rate Billing Determinant Adjustments	X	X			
E	Dividend Distribution Clause (DDC)	X	X			
I	Flexible Priority Firm Power (PF) Rate Option	X	X			
J	General Transfer Agreement Service Charges	X	X	X		
K	Irrigation Rate Discount	X	X	X		
L	Load Shaping Charge Adjustment	X	X			
M	Low Density Discount (LDD)	X	X	X		
N	NFB Mechanisms	X	X			
P	Priority Firm Power (PF) Shaping Option	X	X			
R	Remarketing	X	X			
S	Residential Exchange Program Residential Load				X	
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment				X	
U	Resource Support Services and Transmission Scheduling Service	X	X	X		
V	RHWM Tier 1 System Capability (RT1SC)	X	X			
W	Slice True-Up Adjustment			X		
X	Tier 2 Rate TCMS Adjustment	X				
Y	TOCA Adjustment	X	X			
Z	Unanticipated Load Service	X	X			
AA	Unauthorized Increase (UAI) Charge	X	X	X	X	

<i>GRSP Appendix</i>	<i>Adjustments</i>	<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>	<i>Tier 2</i>
A	REP Settlement Customer Refund Amounts in FY 2016-2017	X	X	X	
B	Tier 2 Load Growth Rate Customer Charge for FY 2016- 2017				X
C	Slice Billing Adjustment			X	

This page intentionally left blank.

SCHEDULE NR-16 NEW RESOURCE FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act. This schedule is available for services provided to Load Following customers that are serving NLSLs with non-Federal resources.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the NR-14 rate schedule. Sales under the NR-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	76.33	72.22
November	77.03	72.95
December	77.69	73.29
January	78.49	73.50
February	78.12	73.15
March	73.85	70.54
April	72.83	69.51
May	70.57	66.00
June	71.62	65.58
July	75.90	70.05
August	78.77	72.88
September	80.22	74.17

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 8.20 mills/kWh.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3 Unanticipated Load Service Charge

The Unanticipated Load Service charge is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.Z.3.

4 Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.G.1, is applicable to Load Following Customers that serve NLSLs with non-Federal resources.

5 NR Resource Flattening Service Charge

The NR Resource Flattening Service charge, specified in GRSP II.G.2, is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

6 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Conservation Surcharge	A.1
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Demand Rate Billing Determinant Adjustments	D
Dividend Distribution Clause (DDC)	E
Energy Shaping Service for NLSLs Charge	G.1
NR Resource Flattening Service Charge	G.2
Flexible New Resource Firm Power (NR) Rate Option	H
Low Density Discount (LDD)	M
NFB Mechanisms	N
Unanticipated Load Service	Z
Unauthorized Increase (UAI) Charge	AA

This page intentionally left blank.

SCHEDULE IP-16 INDUSTRIAL FIRM POWER RATE

1 Availability

This schedule is available to BPA’s direct service industrial (DSI) Customers, as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power is available under Northwest Power Act section 5(d) contracts to DSIs for direct consumption.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2015, this rate schedule supersedes the IP-14 rate schedule. Sales under the IP-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-16 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2 Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	44.43	40.32
November	45.13	41.05
December	45.79	41.39
January	46.59	41.60
February	46.22	41.25
March	41.95	38.64
April	40.93	37.61
May	38.67	34.10
June	39.72	33.68
July	44.00	38.15
August	46.87	40.98
September	48.32	42.27

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 8.20 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.973 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.2 Energy Billing Determinant

The billing determinant is the Energy Entitlement that is specified in the Customer's contract.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

2.2.2 Demand Billing Determinant

The billing determinant is the Customer's maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the Customer's monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

<i>Month</i>	<i>Industrial Demand Adjuster (kW)</i>
October	2046
November	1646
December	1160
January	1019
February	1115
March	1598
April	795
May	1122
June	763
July	793
August	903
September	731

If Port Townsend Paper's Contract Demand is other than 15.75 MW, the Industrial Demand Adjuster values in the above table shall be adjusted proportionally.

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

3 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Conservation Surcharge	A.1
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Demand Rate Billing Determinant Adjustments	D
Dividend Distribution Clause (DDC)	E
DSI Reserves Adjustment	F
NFB Mechanisms	N
Unauthorized Increase (UAI) Charge	AA

This page intentionally left blank.

SCHEDULE FPS-16

FIRM POWER AND SURPLUS PRODUCTS AND SERVICES RATE

1 Availability

This rate schedule is available for the sale of Firm Power (capacity and/or energy), Capacity Without Energy, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, Unanticipated Load Service, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest.

Sales under this rate schedule are discretionary. BPA is not obligated to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2015, this rate schedule supersedes the FPS-14 rate schedule. Sales under the FPS-16 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Firm Power and Capacity Without Energy

2.1 Flexible Rates and Billing Determinants

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the Customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Customer.

3 Shaping Services

3.1 Rates and Billing Determinants

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

4 Reservations and Rights to Change Services

4.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reservation and Rights to Change Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

5 Reassignment or Remarketing of Surplus Transmission Capacity

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

5.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the Customer.

6 Services for Non-Federal Resources

6.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.U.4.

6.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.U.3.

6.3 Resource Remarketing Service (RRS)

Customers that have requested and have been granted permission to take RRS for their non-Federal resources shall receive the RRS credit specified in GRSP II.U.6.

7 Unanticipated Load Service

The Unanticipated Load Service is applicable to the sale of firm power to serve unanticipated loads resulting from a request for service under section 9(i) of the Northwest Power Act. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.Z.4.

8 Other Capacity, Energy, and Scheduling Products and Services

Power Services may sell energy or capacity (including energy or capacity provided to balancing authorities and transmission providers, other than the BPA Balancing Authority, for use as ancillary services) and power scheduling products and services under this rate schedule. Such products and services may include, but are not limited to: (1) interruptible energy; (2) resource support and scheduling services for non-Federal resources not eligible for services under section 6 of this FPS rate schedule; and (3) reserve-based products and services (including but not limited to operating reserves, imbalance energy, frequency response reserves and regulation for use outside the BPA Balancing Authority Area).

8.1 Rates and Billing Determinants

Rate(s) and billing determinant(s) applicable to such products and services shall be as specified by BPA or as agreed to by BPA and the Customer. The charge(s) for these services shall be the applicable rate(s) times the applicable billing determinant(s) pursuant to the agreement between BPA and the Customer.

9 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table and/or as specified by BPA or as agreed to by BPA and the Customer.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Cost Contributions	B
Unauthorized Increase (UAI) Charge	AA

This page intentionally left blank.

GENERAL RATE SCHEDULE PROVISIONS

This page intentionally left blank.

GENERAL RATE SCHEDULE PROVISIONS

Index

I.	ADOPTION OF REVISED POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS	35
A.	Approval of Rates	35
B.	General Provisions	35
C.	Payment Provisions.....	35
D.	Notices	36
E.	Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements.....	36
F.	Metering Usage Data Estimation Provision.....	38
II.	ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS.....	39
A.	Conservation	39
B.	Cost Contributions	39
C.	Cost Recovery Adjustment Clause (CRAC).....	40
D.	Demand Rate Billing Determinant Adjustments	45
E.	Dividend Distribution Clause (DDC)	47
F.	DSI Reserves.....	50
G.	NR Services for New Large Single Loads (NLSL)	51
H.	Flexible New Resource Firm Power (NR) Rate Option	54
I.	Flexible Priority Firm Power (PF) Rate Option.....	55
J.	General Transfer Agreement Service Charges	55
K.	Irrigation Rate Discount.....	57
L.	Load Shaping Charge True-Up Adjustment	59
M.	Low Density Discount (LDD)	61
N.	NFB Mechanisms.....	66
O.	[Reserved for future use]	73
P.	Priority Firm Power (PF) Shaping Option	73
Q.	Priority Firm Power (PF) Tier 1 Equivalent Rates	74
R.	Remarketing.....	75
S.	Residential Exchange Program Residential Load.....	76
T.	Residential Exchange Program 7(b)(3) Surcharge Adjustment.....	77
U.	Resource Support Services and Transmission Scheduling Service	79
V.	RHWM Tier 1 System Capability (RT1SC).....	88
W.	Slice True-Up Adjustment	88
X.	Tier 2 Rate TCMS Adjustment.....	94
Y.	TOCA Adjustment.....	94
Z.	Unanticipated Load Service.....	95
AA.	Unauthorized Increase (UAI) Charge	100

III. DEFINITIONS.....	103
A. Power Products and Services Offered By BPA Power Services	103
B. Definition of Rate Schedule Terms.....	106

Appendices

Appendix A. REP Settlement Customer Refund Amounts in FY 2016–2017	115
Appendix B. Tier 2 Load Growth Rate Customer Charge for FY 2016–2017.....	121
Appendix C. Slice Billing Adjustment	125

GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

The Power rate schedules and these General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (Commission). BPA will request that the Commission make these rates and GRSPs effective on October 1, 2015. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power rate schedules and GRSPs associated with the rate schedules supersede BPA's 2014 Power rate schedules, which became effective October 1, 2013, to the extent stated in the Availability section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: The Bonneville Project Act (Pub. L. No. 75-329), the Regional Preference Act (Pub. L. No. 88-552), the Transmission System Act (Pub. L. No. 93-454), the Northwest Power Act (Pub. L. No. 96-501), and the Energy Policy Act of 1992 (Pub. L. No. 102-486).

The rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365, shall be applied each day to any unpaid balance. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The Customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service Customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services “Facility Ownership and Cost Assignment Guidelines,” as amended or superseded (Transmission Services Guidelines), currently posted at:

http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/BPA_Facility_Ownership_and_Cost_Assignment_Guidelines.pdf

In determining whether to directly assign to a Transfer Customer costs incurred by BPA in providing transfer service to the Customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference Customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most pro forma Open-Access Transmission Tariffs (OATT), are:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer...

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission Customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the Customer.

Supplemental Guideline Regarding Directly-Assigned Facilities

For new facilities or new service over existing third-party transmission provider facilities that meet the definition of Direct Assignment Facilities, metered quantities for Customer deliveries will be adjusted for losses such that BPA is not responsible for losses across such directly assigned facilities. Loss calculations should be similar whether the Customer or the transmission provider owns the directly assigned facilities.

Supplemental Guidelines Regarding Replacement with Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting Customer. Alternatively, BPA and the Customer may agree to full direct assignment in lieu of payment of the GTA Delivery Charge. Similarly, when a parallel transformer is added, BPA and the Customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The Customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the Customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

If a Customer receives new Transfer Service over new or pre-existing facilities offered by the transmission provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the GTA Delivery Charge. BPA will not assess the GTA Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the Customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation

On any new arrangement for a directly assigned facility (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the Customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider

A Customer may, in lieu of paying the GTA Delivery Charge, choose to contract directly with the third-party transmission provider for delivery service at an existing POD, but must then do so for all similar PODs with that transmission provider. The Customer must take transmission service from BPA at these PODs such that the Customer is responsible for costs of and losses through the delivering facilities. A Customer contracting with the

third party for a new POD does not create a requirement that the Customer contract with the third party for its pre-existing low-voltage PODs.

F. Metering Usage Data Estimation Provision

Pursuant to section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering Web site.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation

1. Conservation Surcharge

The Conservation Surcharge, if implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the Customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-16 (including Slice purchasers), IP-16, and NR-16 rate schedules.

2. Large Project Targeted Adjustment Charge (LPTAC)

The Large Project Targeted Adjustment Charge (LPTAC) rate is based on BPA making funds available for the acquisition of conservation through the Large Project Program (LPP). At any time during the rate period, a customer may submit a project to BPA for consideration of funding through the LPP. Customers will be charged the True Acquisition Cost associated with the funding. All non-participating customers will be held harmless to the costs of LPP funding; all costs accrued to BPA associated with LPP will be funded through contractual arrangements between BPA and participating LPP customers. The charge will be implemented on an individual customer basis.

True Acquisition Cost: The LPTAC will incorporate principal and accrued interest at the BPA Fund rate (BPA's opportunity cost for monies in the BPA Fund) from the time of project funding to the time financing is obtained for the program. After financing, LPP contracts will be charged at a vintage-specific rate over the course of the useful life of the conservation asset acquired, as determined by BPA's capitalization policy for Energy Efficiency investments. The LPTAC will also include the costs for issuance and other costs associated with financing for the conservation project.

Fund Cap: No more than \$10 million will be made available during each Rate Period for the LPP.

Eligibility: A Preference customer with a Regional Dialogue contract is eligible to participate. The customer must enter into an LPP agreement that includes the terms and conditions for BPA's acquisition of LPP energy savings from the customer. The customer must submit a completed project proposal, pursuant to the terms in the Implementation Manual, to BPA for consideration. Payment for savings will be made only upon BPA's approval of the project completion report.

B. Cost Contributions

Pursuant to section 7(j) of the Northwest Power Act, BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is:

**Table A
Resource Cost Contribution**

<i>Rate Schedule</i>	<i>Federal Base System</i>	<i>Exchange Resources</i>	<i>New Resources</i>
PF	42.36%	57.64%	0%
IP	0%	46.58%	53.42%
NR	0%	46.58%	53.42%
FPS	0%	47.47%	52.53%

2. The cost of resources acquired to meet load growth within the region is estimated to be 43.09 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 45.49 mills/kWh.

C. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to certain rates that can apply to rates during FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue (ACNR) for the fiscal year preceding the applicable year. If the forecast ACNR is less than the CRAC Threshold for that applicable year by at least \$5 million, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year.

(a) Calculating the Power Calibrated Net Revenue (CNR) and ACNR

The Power CNR is Power net revenue plus the Net Revenue Calibration.

The Net Revenue Calibration is the sum of the effects of a set of differences, one difference calculated for each event not forecast in the BP-16 rate case that affects Power net revenue and Power cashflow (more specifically, changes in Financial Reserves Available for Risk Attributed to Power) differently by more than \$5 million. Such events include certain debt management transactions, settlements of contracts,

and others. For each event, the impact of the event on Power net revenue will be subtracted from the impact on Power cashflow.

The Power ACNR is Power CNR accumulated since the end of FY 2014. A forecast of ACNR is used to determine whether the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of ACNR for use in determining the CRAC that will apply to FY 2016 rates will be the forecast of Power Services' Calibrated Net Revenue for FY 2015. The forecast of ACNR for use in determining the CRAC that will apply to FY 2017 rates will be the sum of the actual Power Services' Calibrated Net Revenue for FY 2015 plus the forecast of Power Services' Calibrated Net Revenue for FY 2016.

(b) Calculating the CRAC Amount

The CRAC Amount is based on the Underrun, which is equal to the CRAC Threshold minus forecast ACNR. There are four possibilities:

- (1) If the Underrun is less than \$5 million, there is no CRAC.
- (2) If the Underrun is greater than or equal to \$5 million and less than or equal to \$100 million, the CRAC Amount is equal to the Underrun.
- (3) If the Underrun is greater than \$100 million and less than \$500 million, the CRAC Amount is equal to \$100 million plus one-half of the difference between \$100 million and the Underrun.
- (4) If the Underrun is greater than or equal to \$500 million, the CRAC Amount is equal to \$300 million.

NOTE: In cases (2), (3), and (4) above, if an NFB Adjustment increases the CRAC Cap from \$300 million to a higher number, the terms will be adjusted. In cases (2) and (3), the "\$100 million" figure will be replaced by \$100 million plus the difference between the new Cap and \$300 million. In cases (3) and (4), the "\$500 million" figure will be replaced by \$500 million plus twice the difference between the new Cap and \$300 million. In case (4), the "\$300 million" figure will be replaced by the new Cap.

The CRAC Cap and thresholds are shown in Table B.

Table B
CRAC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>CRAC Applied to Fiscal Year</i>	<i>CRAC Threshold Measured in ACNR</i>	<i>Approx. Threshold as Measured in Power Services Reserves for Risk</i>	<i>Maximum CRAC Recovery Amount (Cap)*</i>
2015	2016	(\$133.5)	\$0	\$300
2016	2017	(\$86.5)	\$0	\$300

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

Where:

CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate during the year of application.

CRAC Threshold is the “trigger point” for invoking a rate increase under the CRAC.

ACNR is Accumulated Calibrated Net Revenue for the generation function, as described in section 1(a).

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum CRAC Recovery Amount (Cap) is the maximum annual amount that is allowed to be recovered through the CRAC.

(c) Calculating the PF/IP/NR CRAC Amount and the ACS CRAC Amount

The PF/IP/NR CRAC Amount is 91.8 percent times the CRAC Amount.

The ACS CRAC Amount is 8.2 percent times the CRAC Amount.

(d) Converting the PF/IP/NR CRAC Amount to the PF/IP/NR CRAC Surcharge

Once the PF/IP/NR CRAC Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to each of the monthly/diurnal PF Melded, IP, and NR energy rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer Rate.

The PF/IP/NR CRAC Surcharge rate is calculated by dividing the PF/IP/NR CRAC Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR CRAC Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR CRAC Surcharge rate. The product of this calculation is the annual dollar amount to be collected through the Non-Slice TOCA billing determinant.
- (2) Dividing the annual dollar amount to be collected through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(e) CRAC Charges for the PF, IP, and NR Rates

For service under the PF Melded, IP, or NR rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing additional charges calculated by multiplying the PF/IP/NR CRAC Surcharge by the applicable kilowatthours of service.

For service under the Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(f) Converting the ACS CRAC Amount to Charges on Customers' Bills

Once the ACS CRAC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G. for details of how those Transmission rates subject to the CRAC will be modified.

(g) Other Rate Adjustments

The Surcharge rate, calculated pursuant to section 1(d), will be subtracted from the Load Shaping Charge True-Up rate to create the CRAC-Adjusted Load Shaping True-Up Rate. See GRSP II.L.

The Surcharge rate, calculated pursuant to section 1(d), will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.W.1(b).

The Surcharge rate, calculated pursuant to section 1(d), will also be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.Q.

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ACNR forecast for the end of that year. If that amount is below the CRAC Threshold, a CRAC rate adjustment will be made for the next fiscal year.

3. CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function, including ACNR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of ACNR attributable to the generation function.

(b) Notification of CRAC Trigger

BPA shall complete a forecast of end-of-year ACNR in July 2015 for use in calculating the CRAC applicable to rates in FY 2016 and in September 2016 for use in calculating the CRAC applicable to rates in FY 2017. If the forecast value of ACNR is below the CRAC Threshold applicable to the following year by at least \$5 million, then BPA shall notify all Customers and rate case parties by late July 2015 of the amount by which BPA intends to adjust rates for FY 2016 due to the CRAC, and by late September 2016 of the amount by which BPA intends to adjust rates for FY 2017.

Notification will be posted on BPA's Web site and will include the forecast of ACNR for the current fiscal year, the audited NR and the NR Calibration for FY 2015 in the case of the CRAC applicable to FY 2017 rates, the CRAC Amount, the PF/IP/NR CRAC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the CRAC-adjusted Load Shaping True-Up Rate, the CRAC-adjusted PF Melded Equivalent Energy Scalar, the ACS CRAC Amount, and details about how the ACS CRAC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the ACNR calculations, describe the calculation of the CRAC Amount and allocations to various rates, and demonstrate that the CRAC

has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

The Administrator may exercise discretion and elect to reduce the CRAC rate adjustment provided (1) the resulting TPP for the remainder of the rate period is greater than or equal to BPA's TPP standard (95 percent for the FY 2016–2017 rate period in the case of the CRAC applicable to FY 2016 rates; 97.5 percent in the case of the CRAC applicable to FY 2017 rates); and (2) the reduced CRAC will recover in the following year the first \$100 million of any use by BPA of the Treasury Facility or liquidity other than Reserves for Risk attributed to Power to pay Power bills plus one-half of any use of the Treasury Facility or liquidity other than Reserves for Risk attributed to Power beyond \$100 million, up to a maximum of the CRAC Cap as described above. In the case of the CRAC applicable to the FY 2016 rates, the Administrator may modify the parameters for the CRAC applicable to FY 2017 rates to meet the one-year TPP standard for FY 2017; criterion (2) above must still be met. If the Administrator elects to make such a modification, the Customers shall be informed during the workshop.

If the CRAC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.N) to the CRAC Cap. If the CRAC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.N) to the CRAC Cap.

D. Demand Rate Billing Determinant Adjustments

BPA may adjust Customers' bills after the fact for changes to demand charge billing determinants, as described below.

1. Extreme Load Shift Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

If a Customer's monthly CDQ-adjusted HLH load factor (aHLH divided by the quantity (i) Tier 1 CSP minus (ii) CDQ minus (iii) SuperPeak) is less than 55 percent, BPA may recompute a Customer's demand billing determinant for the month. The month shall first be separated into two or more partial-month periods using the extreme load shift events that occur during the month as demarcations for the periods. For each partial-month period, a separate demand value shall be calculated using the same arithmetic method used to compute the Customer's demand billing determinant for the full month, but such calculation shall use only the peak and energy consumed during each partial-month period. If BPA agrees to an adjustment, the largest of the partial-month demand values among the partial-month periods shall be used as the Customer's demand billing determinant for the entire month.

(b) Notification Requirement

The Customer shall be responsible for notifying BPA in the event it believes it may qualify for an extreme load shift demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without Customer notification. BPA will not consider a Customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the Customer's power bill is produced and communicated to the Customer.

2. Recovery Peak Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

The demand CSP may be reduced by the kilowatt difference between the CSP resulting from a Recovery Peak and the next highest HLH peak during the month that is not a Recovery Peak.

Recovery Peak shall mean an extraordinary CSP measured in a Customer's load following return to service from an outage. A Recovery Peak for which BPA would consider a Recovery Peak Demand Billing Determinant Adjustment must have all three of the following characteristics:

- (1) the CSP occurred during one of the two (2) hours immediately following restoration of service after an outage due to an Uncontrollable Force, provided that the outage lasted for two hours or more;
- (2) the outage reduced the utility's Total Retail Load (TRL) by 25 percent or more; and
- (3) the demand billing determinant resulting from such a CSP is ten percent or more of those CSP kilowatts.

In determining the 25 percent threshold, the TRL reduction is computed by comparing the TRL measured during any hour of the outage to the TRL measured in the hour ended immediately prior to the hour in which the outage began. BPA may consider evidence that an observed CSP is not extraordinary. Such evidence may include that substantial restoration of service occurred more than two hours prior to the potential Recovery Peak hour, the hourly load patterns before and after the outage, and loads of similarly situated Customers that did not experience a simultaneous outage due to Uncontrollable Force.

(b) Notification Requirement

The Customer shall be responsible for notifying BPA in the event it believes it may qualify for a demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without Customer notification. BPA shall not consider a Customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the Customer's power bill is produced and communicated to the Customer.

E. Dividend Distribution Clause (DDC)

The DDC is a downward adjustment to certain rates; it can apply to rates during FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The DDC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates.

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue (ACNR) for the fiscal year preceding the applicable year. If the forecast ACNR is greater than the DDC Threshold for that applicable year by at least \$5 million, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the DDC Amount

The DDC Amount will be equal to either the forecast ACNR less the DDC Threshold or \$1,000 million, whichever is smaller.

Table C
DDC Annual Thresholds and Cap
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>DDC Applied to Fiscal Year</i>	<i>DDC Threshold Measured in ACNR</i>	<i>Approx. Threshold as Measured in Power Services Reserves for Risk</i>	<i>Maximum DDC Distribution Amount (Cap)</i>
2015	2016	\$616.5	\$750	\$1,000
2016	2017	\$663.5	\$750	\$1,000

Where:

DDC Amount is the reduction in net revenue that a decrease in rates, due to the DDC, is intended to generate during the year of application.

DDC Threshold is the “trigger point” for invoking a rate decrease under the DDC.

ACNR is Accumulated Calibrated Net Revenue for the generation function, as defined in GRSP II.C.1.(a) above.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum DDC Recovery Amount (Cap) is the maximum annual amount that is allowed to be distributed through the DDC.

(b) Calculating the PF/IP/NR DDC Amount and the ACS DDC Amount

The PF/IP/NR DDC Amount is 91.8 percent times the DDC Amount.

The ACS DDC Amount is 8.2 percent times the DDC Amount.

(c) Converting the PF/IP/NR DDC Amount to the PF/IP/NR DDC Credit

Once the PF/IP/NR DDC Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DDC Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DDC Credit will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and subtracted from the Non-Slice Customer Rate.

The PF/IP/NR DDC Credit rate is calculated by dividing the PF/IP/NR DDC Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR DDC Credit rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR DDC Credit rate. The product of this calculation is the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant.
- (2) Dividing the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) DDC Credits for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing credits calculated by multiplying the PF/IP/NR DDC Credit by the applicable kilowatthours of service.

For service under the PF Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a credit

calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS DDC Amount to Charges on Customers' Bills

Once the ACS DDC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how those Transmission rates subject to the DDC will be modified.

(f) Other Rate Adjustments

The Credit rate, calculated pursuant to section 1(c), will be added to the Load Shaping True-Up Rate to create the DDC-Adjusted Load Shaping True-Up Rate. See GRSP II.L.

The Credit rate, calculated pursuant to section 1(c), will be added to the PFp Melded Equivalent Energy Scalar to create the DDC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.W.1(b).

The Credit rate, calculated pursuant to section 1(c), will also be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.Q.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ACNR forecast for the end of that year; if that amount is above the DDC Threshold, a DDC rate adjustment will be made for the next fiscal year.

(a) DDC Notification Process

BPA shall follow these notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function, including ACNR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of ACNR attributable to the generation function.

(2) Notification of DDC Trigger

BPA shall complete a forecast of end-of-year ACNR in July 2015 for use in calculating the DDC applicable to rates in FY 2016, and in September 2016 for use in calculating the DDC applicable to rates in FY 2017. If the forecast value of

ACNR is above the DDC Threshold applicable to the following year by at least \$5 million, then BPA shall notify all Customers and rate case parties by late July 2015 of the amount by which BPA intends to adjust rates for FY 2016 due to the DDC, and by late September 2016 of the amount by which BPA intends to adjust rates for FY 2017.

Notification will be posted on BPA's Web site and will include the forecast of ACNR for the current fiscal year, the audited NR and the NR Calibration for FY 2015 in the case of the DDC applicable to FY 2017 rates, the DDC Amount, the PF/IP/NR DDC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the DDC-adjusted Load Shaping True-Up Rate, the DDC-adjusted PF Melded Equivalent Energy Scalar, the ACS DDC Amount, and details about how the ACS DDC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of DDC calculations as described above, BPA shall conduct a workshop(s) to explain the ACNR calculations, describe the calculation of the DDC Amount and allocations to various rates, and demonstrate that the DDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the DDC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final DDC calculations. If the DDC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the BPA Web site the final DDC calculations.

F. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to section 7(c)(3) of the Northwest Power Act (16 U.S.C. § 839e(c)(3)), a DSI Customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. The DSI Operating Reserve – Supplemental is a contractual right for BPA to interrupt DSI load being served with Industrial Firm Power in a megawatt amount equal to 10 percent of the amount of power scheduled for delivery at the time the interruption request occurs. The Minimum DSI Operating Reserve – Supplemental provided by a DSI Customer must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, including the following:

1. The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA.

2. In the event of a system disturbance, the interruptible load or increased generation must be accessible in advance of any need for BPA to request reserves from other Northwest Power Pool members.
3. The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.
4. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

Optional Reserves. BPA is not obligated to purchase any DSI Reserves(s) beyond the Minimum DSI Operating Reserve – Supplemental. However, BPA’s contracts with DSI Customers contain a contingent right to purchase additional reserves to the extent they are needed for operational purposes and can be made available by the Customer. These contract provisions are designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the price for such reserves based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost-effective, the maximum amount to be paid by Power Services is capped at \$7.62 per kW per month.

The availability of optional DSI Reserve(s) purchased by BPA must be consistent with NERC, WECC, and NWPP standards and criteria specific to balancing authority area Operating Reserve Requirements, including the following characteristics:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased.
2. The interruptible load or increased generation must be accessible in advance of any need to request reserves from other Northwest Power Pool members.

In addition to these two characteristics, the issues identified below will guide consideration of when BPA may pay the maximum value for DSI Reserves:

1. The degree to which BPA has discretion with respect to when and how to use the reserves and to determine what resources to call on in the event of system disturbance or for some other purpose specified in any negotiated agreement for optional reserves.
2. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

G. NR Services for New Large Single Loads (NLSLs)

NR Services for NLSLs are applicable to Load Following Customers serving NLSLs with non-Federal resources.

1. NR Energy Shaping Service

1.1 NR Energy Shaping Service Energy Charge

The energy component of the NR Energy Shaping Service either credits or debits the Customer for the difference between energy amounts provided by the Customer's non-Federal resources serving NLSLs and the measured load of their NLSLs.

The NR ESS energy charge can be either positive or negative and is determined through a two-step process. The first step determines the applicable rate treatment, A or B. The second step applies the rate treatment determined in the first step.

Step 1:

Determine if the Customer received energy from BPA or provided energy to BPA on a net monthly basis, calculated as the measured load of the Customer's NLSLs in the billing month minus the energy amounts provided by the Customer's resources to serve their NLSLs during the same billing month. If this result is greater than zero, energy was purchased from BPA, and rate treatment A applies. If this result is zero or negative, rate treatment B applies.

Step 2:

ESS Energy Rate Treatment A.

Calculate two energy billing determinants for each month, one for HLH and one for LLH. Each monthly energy billing determinant is equal to (1) the total measured load of the Customer's NLSL(s) receiving this service during the monthly/diurnal period minus (2) the energy amounts provided by the Customer to serve those NLSLs during that same monthly/diurnal period. The billing determinant for either period can be negative. These billing determinants are multiplied by the applicable monthly/diurnal NR energy rates to calculate the energy charge (or credit). Section 2.1.1 of the NR rate schedule includes 24 Energy rates (two diurnal periods—HLH and LLH—for each of 12 months).

ESS Energy Rate Treatment B.

Calculate daily diurnal billing determinants for the month, resulting in two billing determinants for each day with both HLH and LLH periods and one billing determinant for each day with only a LLH period. Each energy billing determinant is equal to (1) the total measured load of the Customer's NLSL(s) receiving this service during that daily/diurnal period minus (2) the energy amounts provided by the Customer to those NLSLs during that same daily/diurnal period. The billing determinant for any period can be negative. These billing determinants are multiplied by the applicable Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) for the same daily/diurnal period to calculate each daily/diurnal period energy charge. If a Mid-C price for any period is less than zero, the applicable rate for that period will be zero.

The monthly sum of such daily/diurnal energy charges may be adjusted as follows:

- Threshold 1: No adjustment is made if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (i) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (ii) 1,488 MWh.
- Threshold 2: If Threshold 1 is exceeded, Threshold 2 will apply if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (i) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (ii) 3,720 MWh. If Threshold 2 applies, the monthly sum of the daily/diurnal energy charges will be multiplied by 94 percent if the monthly sum is negative (money owed to the Customer) or multiplied by 106 percent if the monthly sum is positive (money owed to BPA).
- Threshold 3: If both Threshold 1 and 2 are exceeded, Threshold 3 applies. When applying Threshold 3, the monthly sum of the daily HLH plus LLH energy charges is multiplied by 84 percent if the monthly sum is negative (money owed to the Customer), or multiplied by 116 percent if the monthly sum is positive (money owed to BPA).

1.2 NR Energy Shaping Service Capacity Charge

The billing determinant for the NR ESS Capacity Charge is the amount of capacity the Customer requests from BPA for standing ready to serve its NLSLs. The Customer must have established monthly capacity amounts for the FY 2016-2017 rate period prior to February 1, 2015. However, at least 30 days prior to any month, the Customer may notify BPA of a change to the amount of capacity it is requesting BPA to stand ready to serve its NLSLs for that month.

The billing determinant is multiplied by the applicable monthly NR demand rate (NR Rate Schedule section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify the Customer's actual capacity use did not exceed the monthly amount of capacity it requested BPA to provide. The actual capacity used is equal to (1) the largest hourly energy amount provided by BPA during the HLH of the month through the NR ESS minus (2) the greater of (i) the average HLH energy provided by BPA under Rate Treatment A, in that same month, or (ii) zero. The Unauthorized Increase (UAI) Charge for demand will apply to the actual capacity used in excess of the monthly amounts of capacity included in the Customer's request to BPA.

2. NR Resource Flattening Service

The NR Resource Flattening Service (NRFS) is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

2.1 NR Resource Flattening Service Energy Charge

The NRFS energy charge is the product of multiplying the NRFS energy rate by the NRFS energy billing determinant for each month.

2.2 NR Resource Flattening Service Energy Rate

NRFS is a unique energy rate developed for each resource to which NRFS is applied. For each monthly/diurnal period in a year, the sum of the hourly planned generation in excess of average monthly/diurnal planned generation amounts is multiplied by 25 percent (to reflect the energy lost when using a pumped storage hydroelectric unit to perform the energy storage). The result is multiplied by the applicable monthly/diurnal Resource Shaping rate. The monthly/diurnal results are summed for the year and divided by the total planned energy amounts to calculate the NRFS Energy rate.

2.3 NR Resource Flattening Service Energy Billing Determinant

The NRFS energy billing determinant is the total actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or the resource transmission schedules if the resource requires an e-Tag.

H. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-16 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in sections 2 and 3 of the NR-16 rate schedule been applied to the same sales.
- The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2 and 3 of the NR-16 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-16 rate and associated GRSPs, any rights and obligations of BPA and a Customer arising out of the Customer's election to participate in

the Flexible NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

I. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA’s discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-16 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in sections 2, 3, 4, and 5 of the PF-16 rate schedule been applied to the same sales.
- The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2, 3, 4, and 5 of the PF-16 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-16 rate and associated GRSPs, any rights and obligations of BPA and a Customer arising out of the Customer’s election to participate in the Flexible PF Rate program by purchasing under the Flexible PF Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

J. General Transfer Agreement Service Charges

The General Transfer Agreement Service applies to BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements.

1. GTA Delivery Charge

The GTA Delivery Charge shall apply to Power Services Customers that purchase Federal power that is delivered over non-Federal low-voltage facilities. Low-voltage facilities are generally facilities operated below 34.5 kV.

(a) GTA Delivery Rate

	<i>Rate in \$/kW</i>
All months	0.94

(b) GTA Delivery Billing Determinant

The monthly billing determinant for the GTA Delivery rate shall be the total load on the hour of the Total Customer System Peak minus behind-the-meter dedicated resources or resources contractually committed to serve Customer load at the low-voltage Points of Delivery provided for in GTA and other non-Federal transmission service arrangements.

2. Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge shall apply to Public Customers that meet the following criteria: (1) BPA serves the Customer under a GTA or other non-Federal transmission service agreements; and (2) the Customer is not paying BPA Transmission Services for operating reserve for the Customer’s load pursuant to WECC standard BAL-002-WECC-2.

(a) Transfer Services Operating Reserve Rate

- (1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-16 Operating Reserve – Spinning Reserve Service rate.
- (2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-16 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Services Operating Reserves Billing Determinant

- (1) The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the metered load of the Customer served by transfer (non-BPA Balancing Authority Area load).
- (2) The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the metered load of the Customer served by transfer (non-BPA Balancing Authority Area load).

3. Transfer Services WECC Charge

The Transfer Services WECC Charge shall apply to Public Customers with load outside the BPA Balancing Authority Area.

(a) Transfer Services WECC Rate

	<i>Rate in mills/kWh</i>
All months	0.03

(b) Transfer Services WECC Billing Determinant

The monthly billing determinant for the Transfer Services WECC Charge shall be the metered load at points of delivery of the Public Customer served by transfer (non-BPA Balancing Authority Area load).

4. Transfer Services Peak Charge

The Transfer Services Peak Charge shall apply to Public Customers with load outside the BPA Balancing Authority Area.

If the Peak Reliability Coordinator does not assess any charges to BPA for Transfer Services customer loads outside the BPA Balancing Authority Area, Public Customers will not be assessed the Transfer Services Peak Charge.

(a) Transfer Services Peak Rate

	<i>Rate in mills/kWh</i>
All months	0.04

(b) Transfer Services Peak Billing Determinant

The monthly billing determinant for the Transfer Services WECC Charge shall be the metered load at points of delivery of the Power Services Customer served by transfer (non-BPA Balancing Authority Area load).

K. Irrigation Rate Discount

1. Discount for Eligible Customers

Section 3 of Exhibit D of the CHWM Contracts describes Irrigation Rate Mitigation (IRM), and section 10.3 of the Tiered Rate Methodology describes an Irrigation Rate Mitigation Product (IRMP). Both the IRM and IRMP are implemented through the Irrigation Rate Discount (IRD) set forth in this provision.

In May, June, July, August, and September, an eligible Customer shall have the Irrigation Rate Discount of 11.77 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

The eligibility amounts for the Irrigation Rate Discount are set forth in section 3.1 of Exhibit D of the CHWM Contracts and are subject to the True-Up process referenced in section 3.2 and described more fully below.

For a Load Following or Block Customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block Customer, the energy purchased at Tier 1 rates will be equal to the sum of the Customer's monthly Block purchase at Tier 1 rates plus the Customer's Slice percentage multiplied by the monthly/diurnal RHWMTier 1 System Capability.

The Irrigation Rate Discount for a Joint Operating Entity (JOE) will be calculated based on individual utility members' loads and billed to the JOE and designated for each eligible utility.

BPA requires a participating Customer to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The Customer may use its Energy Efficiency Incentive fund for this purpose.

2. Metering Requirements

The Customer is required to read irrigation meters at the beginning of May and after the end of the Irrigation Rate Discount season (September 30). The Customer shall provide to BPA monthly metered irrigation load information for the months of May through September in a form that is acceptable to BPA no later than October 31 of each year to ensure a timely True-Up calculation.

3. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the Customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. The actual metered irrigation kilowatt-hour amounts submitted by the Customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts.

If the sum of a Customer's May through September measured irrigation load is less than the sum of the May through September billed irrigation load amounts, a True-Up calculation is required. However, if the sum of a Customer's May through September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a True-Up calculation is not applicable.

The True-Up is calculated as follows: The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the True-Up reimbursement. The True-Up reimbursement shall appear as a charge on a subsequent monthly power bill.

L. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to Customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and shall appear on the Customers' power bills.

1. Load Shaping Charge True-Up Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2016	-8.85
2017	-8.85

2. Load Shaping Charge True-Up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each Customer determines whether the Customer may be eligible for a True-Up charge or credit.

$$\text{Annual Deviation} = \frac{\text{Actual Annual Tier 1 Load (measured)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

TOCA Load is the annual amount of energy that is used to calculate the Customer's TOCA. If the Customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.Y, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-Up; see Special Implementation Provision, section 3 below.

(b) True-Up Credit

If Annual Deviation is positive, the Customer is eligible for a True-Up credit if Above-Forecast Amount is positive (greater than zero).

$$\text{Above-Forecast Amount} = \frac{\text{RHW (calculated)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

If Above-Forecast Amount is positive, the True-Up Credit billing determinant equals negative one (-1) multiplied by the lesser of:

- (1) Annual Deviation, or
- (2) Above-Forecast Amount.

There is no True-Up if Above-Forecast Amount equals zero (0).

(c) True-Up Charge

If Annual Deviation is negative, the Customer may be subject to a True-Up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation, the Customer is subject to a True-Up charge.

$$\begin{array}{rcl} \text{True-Up Charge} & & \text{Absolute value of the Annual Deviation} \\ \text{Billing Determinant} & = & \text{minus} \\ & & \text{Above-RHWM Load} \end{array}$$

The True-Up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

(a) the Customer has Above-RHWM load

and

(b) the Customer has an Above-Forecast Amount greater than zero.

If both these conditions are met, the Customer may be eligible for an additional Load Shaping True-Up credit.

If the Annual Deviation is negative or zero and the absolute value of the Annual Deviation is less than the Customer’s Above-RHWM load, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the least of (i) the Customer’s Above-RHWM load; (ii) the Above-RHWM load minus the absolute value of the Annual Deviation; or (iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the lesser of (i) the Customer’s Above-RHWM load; or (ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is equal to the Load Shaping Charge True-Up Rate multiplied by the sum of (i) the True-Up Credit billing determinant; (ii) the True-Up Charge billing determinant; and (iii) the Special True-Up Credit billing determinant.

The final Load Shaping Charge True-Up Adjustment for each Customer shall be applied as either a one-month credit (if the adjustment is negative) or a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping

Customers have the option to pay the entire charge in one month. There shall be no interest component applied to the Load Shaping Charge True-Up payment schedule.

M. Low Density Discount (LDD)

1. Application and Definitions

For eligible Customers, as defined in section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-16 Composite Customer charge, PF-16 Non-Slice Customer charge, PF-16 Load Shaping charge, PF-16 Load Shaping Charge True-Up Adjustment, and PF-16 demand charge. The LDD also applies to eligible Customers under the PF-16 Melded rate schedule and the NR-16 rate schedule. The LDD shall be applied to only those charges listed in this GRSP I.M.

For Load Following and Block purchases, the applicable discount percentage will apply to all charges for purchases by the Customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, Load Shaping Charge True-Up Adjustment, and demand charge). The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

For Slice/Block purchases, an LDD dollar benefit will be calculated by BPA as though it was a Load Following purchase. BPA will use the Customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the Customer's monthly power bills over the next 12 months. There will be no separate Slice and Block LDD benefits calculated. The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

The eligible and applicable discount percentages shall be revised annually based on data supplied by June 30 of each calendar year (CY) for the previous calendar year and shall become effective on the following October 1.

The calculation of the ratios below shall be based on calendar year data the Customer provides from its annual financial and operating reports (*e.g.*, Rural Utilities Service Financial and Operating Report - Electrical Distribution, National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (CFC Form 7), audited financial report, or Annual Report). The provided annual financial and operating reports shall include the Customer's Total Retail Load, depreciated electric plant, number of consumers, pole miles of distribution lines, total kilowatthours sold, and total electric retail sales revenue. The annual financial and operating report is to be enclosed with the Customer's calendar year data if not previously submitted to BPA. The Customer shall certify that the data submitted is true and correct.

Load acquired by a Customer as a direct result of retail access rights established by Federal, state, or local legislation, that would not otherwise have been acquired absent such legislation, is not eligible to receive the benefits provided by the LDD. The

Customer shall certify that the data submitted does not include such load. The Customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the Customer based on the Customer's entire electric utility system in the Pacific Northwest (PNW). For Customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Customer separately on the Customer's system in the PNW and on the Customer's entire electric system, including areas outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the Customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Customer's eligibility for the LDD shall be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a Customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios (see below), the Customer shall be ineligible for the LDD effective the following October 1. The Customer may reapply for the LDD in any subsequent year.

If a Customer's data and reports are submitted prior to the June 30 deadline, and a revision is necessary, the Customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatthour/Investment Ratio

The Kilowatthour/Investment (K/I) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The K/I ratio is calculated by dividing the Customer's Total Retail Load during the previous calendar year by the value of the Customer's depreciated electric plant (excluding generation plant) at the end of the previous calendar year.

(b) The Consumers/Pole Miles Ratio

The Consumers/Pole Miles (C/M) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the Customer's number of consumers within the distribution system at the end of the previous calendar year, as defined below, by the number of pole miles of distribution lines at the end of the previous calendar year.

"Consumers" means the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) are counted on the basis of the number of residences served. If one meter serves two residences, then two consumers are counted. If a water heater is

metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential consumer will not be counted as an additional consumer.

Additional meters used for net metering consumers will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting shall be counted by the number of billings, regardless of the number of lights per billing.

Pole miles of distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5 kV or below to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

2. Eligibility Criteria

To qualify for a discount, the Customer must meet all five of the following eligibility criteria:

- (a) The Customer must serve as an electric utility offering power for resale to retail consumers.
- (b) The Customer must agree to pass the benefits of the discount through to its eligible consumers within the region served by BPA.
- (c) The Customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 41.00 mills/kWh for FY 2016 and FY 2017.
- (d) The Customer's K/I ratio must be less than 100.
- (e) The Customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a Customer is eligible for a discount. Such determination shall not be dependent on whether the Customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount percentage

For each Customer, an eligible discount percentage shall be determined using Table D below. The eligible discount percentage shall be the sum of the two potential discount percentages for which the Customer qualifies, based on Table D. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to sections 4, 5, and 6 below.

Table D
LDD Eligible Discount percentage

<i>Percentage Discount</i>	<i>Applicable Range for kWh/Investment (K/I) Ratio</i>	<i>Applicable Range for Consumers/Mile (C/M) Ratio</i>
0.0%	35.0 < X	12.0 < X
0.5%	31.5 < X < 35.0	10.8 < X < 12.0
1.0%	28.0 < X < 31.5	9.6 < X < 10.8
1.5%	24.5 < X < 28.0	8.4 < X < 9.6
2.0%	21.0 < X < 24.5	7.2 < X < 8.4
2.5%	17.5 < X < 21.0	6.0 < X < 7.2
3.0%	14.0 < X < 17.5	4.8 < X < 6.0
3.5%	10.5 < X < 14.0	3.6 < X < 4.8
4.0%	7.0 < X < 10.5	2.4 < X < 3.6
4.5%	3.5 < X < 7.0	1.2 < X < 2.4
5.0%	X < 3.5	X < 1.2

4. LDD Phase-In Adjustment

If the Customer satisfies the eligibility criteria in section 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage shall be one of the following amounts:

- (a) the existing eligible discount percentage plus a maximum of one-half percent if the calculated eligible discount percentage exceeds the existing discount; or
- (b) the existing eligible discount percentage minus a maximum of one-half percent if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula shall be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The Customer is not eligible to receive any discount, effective each October, if the Customer fails to meet the eligibility criteria in sections 2(a) through (e) above. If the Customer is eligible to receive a discount in a year following a year in which the Customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above shall apply to the most recent eligible discount.

5. Additional Adjustment for Very Low Densities

If a Customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the eligible discount percentage pursuant to sections 3 and 4 above, an additional one-half percent shall be added to the Customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent. In subsequent years, the one-half percent added to the eligible discount percentage pursuant to this section shall not be included when determining the applicable discount percentage pursuant to section 4 above.

6. Applicable Discount for Customers with Above-RHWM Load

A discount is not provided for the costs of power used to serve the Customer's Above-RHWM load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM load was included. This adjustment modifies the Customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the Customer's power bill during the rate period is:

$$\text{applicableLDD} = \text{eligibleLDD} \times \max \left(\frac{\text{adjTRL}}{\text{RHWM}}, 1.0 \right)$$

Where:

applicableLDD = the discount percentage to be applied to the Tier 1 charges on a Customer's bill

eligibleLDD = the Customer's eligible discount percentage as computed according to sections 2 through 5 above

adjTRL = the Customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the RHWM Process for the applicable fiscal year

RHWM = the Customer's Rate Period High Water Mark for the applicable fiscal year

Any Customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. Treatment for Joint Operating Entity

The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility member under the Tier 1 rates according to section 1 above. The monthly LDD benefit for demand for a JOE is calculated as follows:

- (a) Each individual utility member's demand billing determinant is calculated as if such member were not a member of a JOE.
- (b) The demand billing determinants for all individual utility members are summed.

- (c) The individual utility members' calculated demand billing determinants are scaled (up or down) so that the sum of all individual utility members' calculated demand billing determinants equals the JOE's demand billing determinant.
- (d) The demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 demand charge.
- (e) The demand LDD benefits of the eligible individual members of the JOE are summed to yield the demand LDD benefit to the JOE.

N. NFB Mechanisms

The two NFB mechanisms described here are rate features that allow BPA to recover additional revenue if financial impacts ("Financial Effects") from a specified set of circumstances ("Trigger Events") in the fish and wildlife arena cause a reduction in Power Services' forecast Net Revenue. The first mechanism, the NFB Adjustment, would increase the CRAC Cap applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The second mechanism, the Emergency NFB Surcharge, would increase rates within the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The latter situation would apply if waiting until the next year for additional cost recovery would be imprudent because BPA is in a "cash crunch" (defined in section 3 below).

1. Definitions

- (a) An NFB Trigger Event is one of the following events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those adopted in the most recent wholesale power rate proceeding as modified prior to this Trigger Event:
 - (1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding an FCRPS Biological Opinion (BiOp) issued by NMFS (also known as NOAA Fisheries Service) or the U.S. Fish and Wildlife Service, or any appeal thereof ("Litigation").
 - (2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, Litigation.
 - (3) A new FCRPS BiOp.
 - (4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, Litigation.
 - (5) Actions or measures ultimately required under the 2014 Supplemental FCRPS BiOp that differ from the 2014 Supplemental FCRPS BiOp implementation forecast in the rate case.
- (b) Financial Effects of a Trigger Event are net reductions in estimated Power Services' Net Revenue due to a Trigger Event that affects power sales revenues, fish and

wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, USACE and Reclamation O&M expenses, direct program expenses of the USFWS, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations adopted in the most recent wholesale power rate proceeding, as modified by any previous Trigger Events. These effects are the total effects on the BPA System, excluding the operational or expense effects borne by Slice Customers.

- (c) The Agency Within-Year TPP is the probability that BPA (including both Power Services and Transmission Services) will be able to meet all Agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurs. Agency Within-Year TPP takes into account, for the remainder of such fiscal year: (i) all funds reasonably expected to be available to BPA to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), any expense reductions and revenue increases, short-term borrowing available through the Treasury Facility (which availability may be limited by constraints on BPA's remaining borrowing authority), and BPA's then-current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the BP-16 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.
- (d) Surcharge Amount is the amount of money to be collected under the Emergency NFB Surcharge.
- (e) Revenue Basis is the 12-month total of revenue from Power rates subject to the Emergency NFB Surcharge for a specific fiscal year.
- (f) Customer percentage is the Revenue Basis associated with each Customer divided by the total Revenue Basis. Each Customer percentage shall be rounded to four decimal places.

2. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the BP-16 rates, the NFB Adjustment calculation can result in an increase in the annual CRAC Cap set forth in Table B in GRSP II.C if an NFB Trigger Event occurs prior to the fiscal year to which a CRAC is applied.

$$\text{NFB Adjustment} = \text{Financial Effects of Trigger Event(s)}$$

$$\text{Adjusted CRAC Cap} = \text{CRAC Cap from Table B} + \text{NFB Adjustment}$$

See GRSP II.C.1(b) for additional detail.

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified rates during a year in which (a) Financial Effect(s) occur from a Trigger Event(s) and (b) the Agency Within-Year TPP is below 80 percent (also referred to as a cash crunch). A “cash crunch” means the Agency Within-Year TPP is calculated to be below 80 percent including (1) the Financial Effects of all Trigger Events and (2) all revenues from those, but only those, CRACs and Emergency NFB Surcharges that have already been implemented (*i.e.*, calculated, and scheduled to be affecting rates). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

For the BP-16 rates, the Surcharge may be implemented in FY 2016 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2017 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2016 or FY 2017 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-16)
- PF Melded rate (PF-16)
- Industrial Firm Power rate (IP-16)
- New Resource Firm Power rate (NR-16)

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-16) rates

There can be more than one Trigger Event in a year, and therefore there could be more than one Surcharge implemented in a fiscal year.

At the discretion of the Administrator, BPA may collect the Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

No Surcharge will be levied if the Surcharge Amount described below is calculated to be less than \$10 million. If the first month in which the Surcharge bill is sent out occurs during the last quarter of the fiscal year in which the Trigger Event occurred, then the Surcharge Amount in each such month shall not exceed \$25 million.

If Surcharge revenues total less than the total Financial Effects for Trigger Events in that year, the remaining balance of Financial Effects will be included in an NFB Adjustment to the CRAC Cap for the subsequent year.

4. Calculations for the NFB Emergency Surcharge

(a) Calculating the NFB Surcharge Amount

NFB Surcharge Amount = Financial Effects of Trigger Event

(b) Calculating the PF/IP/NR Surcharge Amount and the ACS Surcharge Amount

The PF/IP/NR Surcharge Amount is 91.8% times the Surcharge Amount.

The ACS Surcharge Amount is 8.2% times the Surcharge Amount.

(c) Converting the PF/IP/NR Surcharge Amount to the PF/IP/NR Surcharge

Once the PF/IP/NR Surcharge Amount is determined, that amount will be converted to a mills-per-kilowatthour Surcharge rate added to the IP and NR rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate (making a negative Non-Slice Customer rate less negative).

The PF/IP/NR Surcharge rate is calculated by dividing the PF/IP/NR Surcharge Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable months of the applicable year.

The PF/IP/NR Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by multiplying the sum of PF System Shaped Loads for the applicable months by the PF/IP/NR Surcharge rate. The product of this calculation is the dollar amount to be collected through the Non-Slice TOCA billing determinant. The dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by the applicable months in the fiscal year. The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) Customer Charges for the PF/IP/NR Surcharge

Line items will be added to the bills during the applicable months of the applicable year for service under PF Melded, IP, and NR rates showing additional charges calculated by multiplying the PF/IP/NR Surcharge rate by the applicable kilowatthours of service.

A line item will be added to the bills during the applicable months of the applicable year for service under PF rates showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS Surcharge Amount to Charges on Customers' Bills

Once the ACS Surcharge Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how those Transmission rates subject to the Surcharge will be modified.

(f) Other Rate Adjustments

The PF/IP/NR Surcharge rate will be converted to an annual Surcharge rate. The annual Surcharge rate is calculated as the PF/IP/NR Surcharge rate multiplied by the quotient of the sum of PF System Shaped Loads for the applicable surcharge months divided by the annual sum of PF System Shaped Loads.

The annual Surcharge rate will be applied to the Load Shaping True-Up Rate to create the Surcharge-Adjusted Load Shaping True-Up Rate. The annual Surcharge rate will be applied to the PF Melded Equivalent Energy Scalar, see GRSP II.W.1(b), to create the Surcharge-Adjusted PF Melded Equivalent Energy Scalar.

The PF/IP/NR Surcharge will also be applied to the applicable months of the PF Tier 1 Equivalent energy rates. See GRSP II.Q.

5. Criteria for Applying the NFB Adjustment or Assessing the Surcharge

NFB Trigger Events that have Financial Effects can lead to NFB Adjustments or Surcharges according to these GRSPs if they occur in fiscal years 2015, 2016, or 2017. Whether such Trigger Events lead to NFB Adjustments or to Surcharges depends on whether BPA is in a cash crunch in the year in which the Trigger Event occurs.

If a Trigger Event occurs in FY 2015, it may result in a Surcharge for FY 2015 if BPA is in a cash crunch in FY 2015. Such a Surcharge would be governed by the BP-14 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the BP-14 GRSPs during FY 2015 collects less than the full amount of the FY 2015 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the CRAC Cap applicable to FY 2016 and 2017, as governed by these BP-16 GRSPs.

If a Trigger Event occurs in FY 2016, it may result in either a Surcharge applicable to FY 2016 rates or an NFB Adjustment to the CRAC Cap applicable to FY 2017 rates. Such a Trigger Event may result in both NFB mechanisms being used if some but not all of the Financial Effects were recoverable from a Surcharge in FY 2016. All of these possibilities will be governed by these GRSPs.

If a Trigger Event occurs in FY 2017 and BPA is in a cash crunch, the Surcharge procedures defined in these GRSPs will apply. If BPA is not in a cash crunch in FY 2017, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2018 rates based on Trigger Events occurring in FY 2017 will be defined later by the 2018 GRSPs.

If a Trigger Event occurs that has Financial Effects in the year of its occurrence and also in later years, the Trigger Event will be deemed to have occurred on the first day of all subsequent years in which it has Financial Effects (*i.e.*, Financial Effects that have not been incorporated into the general rates applicable to that year). If there are, or are deemed to be, multiple Trigger Events in any fiscal year, the Financial Effects of those events will be the net effect for that fiscal year of all Trigger Events combined.

6. NFB Adjustment and Surcharge Notification Processes

BPA shall use the following procedures following a Trigger Event:

(a) Notification of Trigger Event and Related Workshops

BPA will notify Customers within 30 days of the occurrence of an NFB Trigger Event in FY 2016 or FY 2017, as defined above, if BPA estimates the Financial Effects of the Trigger Event to be \$10 million or more. This initial notification, posted to BPA's Web site and provided by e-mail to those listed on the service list for the BP-16 rate proceeding, will include a description of the Trigger Event. BPA may elect not to notify Customers of the Trigger Event if BPA estimates the Financial Effects of a Trigger Event to be less than \$10 million or BPA expects that neither a CRAC applicable to the subsequent year nor a Surcharge resulting from the Trigger Event applicable to the current year will be implemented.

If BPA does not determine that the Agency Within-Year TPP is below 80 percent at any later time in the fiscal year, a Trigger Event with Financial Effects will result in an NFB Adjustment. The Financial Effects of the Trigger Event will be presented along with the forecast of the end-of-year ACNR calculation in July 2015 (for an FY 2016 Adjustment) or September 2016 (for an FY 2017 Adjustment). There can be more than one NFB Adjustment Trigger Event in a year. There will be only one, if any, calculation of the NFB Adjustment to the CRAC Cap applicable to the next year.

If the ACNR is forecast to fall below the CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the CRAC procedures in GRSP II.C. At the workshop(s), BPA will explain the Trigger Event and the estimated Financial Effects. BPA will provide and explain the data, models, and assumptions used to calculate the Surcharge Amount. BPA will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the Customer's request, BPA Account Executives shall provide Customers details of their charges under the Surcharge.

If the CRAC applicable to FY 2016 rates triggers, then on or about July 31, 2015, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap. If the CRAC applicable to FY 2017 rates triggers, then on or about September 30, 2016, BPA will post to the

BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap.

(b) Notification of Agency Within-Year TPP Falling Below 80 percent Following a Trigger Event, and Related Workshops

If, during a fiscal year in which a Trigger Event has occurred, BPA determines that the Agency Within-Year TPP is below 80 percent, BPA will notify Customers within seven (7) days of such a determination. In addition, this notification will be posted to BPA's Web site and provided by e-mail to parties on the service list for the BP-16 rate proceeding.

This notification will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notification. This notification will also include updated calculations of the Financial Effects of the Trigger Event(s) and the Agency Within-Year TPP. Concurrently, BPA's Account Executives will inform Customers of their charges under the Surcharge.

At this workshop, BPA will explain the calculation of the Agency Within-Year TPP and the Surcharge Amount, including the monthly shape of payments.

BPA will provide data and assumptions used in these calculations. BPA will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(c) Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notification to each Customer in accordance with the notification provisions of the Customer's BPA contract no later than seven (7) days following the conclusion of the workshop described above. Such Final Notification will state the monthly Surcharge Amount and the total Surcharge Amount to be recovered from each Customer by September 30 of the fiscal year in which the Surcharge is in effect.

The monthly Surcharge Amount will be included on bills to Customers and will be payable in accordance with the applicable payment provisions of the Customers' contracts. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

(d) Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notification of implementation of a Surcharge described above, BPA will provide notice of two or more meetings to be completed within sixty (60) days of the Final Notification.

At the first meeting, Customers and interested persons may request additional information and explanations about the Trigger Event, its Financial Effects, and the updated Agency Within-Year TPP. Customers and interested persons may also request information regarding BPA's financial performance to date, revenue and expense forecasts for the remainder of the fiscal year, the calculation of the Surcharge Amount, and any other materials related to the Surcharge then in effect. BPA will provide responses to relevant information requests as promptly as possible, but in any case no later than 48 hours prior to the final meeting. Subsequent meetings may be held as necessary.

At the final meeting, Customers and interested persons may ask questions of and present their views to the Administrator. Customers and interested persons may also submit their views in writing to the Administrator within seven days after the meeting.

Based on the information and views presented during the process provided for in this section, and not later than twenty (20) days after the final meeting, the Administrator will issue a close-out letter that addresses the issues raised in the meetings, the need for the Surcharge, and whether the Surcharge is set at the appropriate level, all in accordance with these GRSPs. If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to Customers for the amounts over-collected, or adjust the Surcharge then in effect for the remainder of the year. The Administrator may remove the Surcharge entirely if one or both of the following occur:

- (1) the Agency Within-Year TPP, not including future surcharge payments, is determined at the time of the close-out letter to be greater than 90 percent; or
- (2) an updated calculation indicates that the Financial Effects of the Trigger Event(s) are less than \$10 million for that fiscal year.

O. [Reserved for future use]

P. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a Customer purchasing Firm Requirements Power charged under section 2.1 of the PF-16 rate schedule may agree to a PF-16 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-16 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual Customer requests to "shape" certain PF-16 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the Customer. The shaped payments at PF-16 Tier 1 Customer rates will be mutually agreed to by BPA and the Customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2015.

This Shaping Option analysis will take into account the cash-flow impacts to the Customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly demand charges; and any applicable rate discounts. BPA and the Customer may agree to 12 monthly Composite Customer charges that the Customer shall pay in each year of the rate period. If further shaping is requested to mitigate a Customer's cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping.
2. No Material Adverse Impacts on BPA's Cash Flow: The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

Q. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

<i>Month</i>	<i>Energy Rate in mills/kWh</i>		<i>Demand Rate in \$/kW</i>
	<i>HLH</i>	<i>LLH</i>	<i>HLH</i>
October	36.71	32.60	10.02
November	37.41	33.33	10.27
December	38.07	33.67	10.51
January	38.87	33.88	10.79
February	38.50	33.53	10.66
March	34.23	30.92	9.13
April	33.21	29.89	8.76
May	30.95	26.38	7.95
June	32.00	25.96	8.33
July	36.28	30.43	9.87
August	39.15	33.26	10.90
September	40.60	34.55	11.42

R. Remarketing

1. Tier 2 Remarketing for Individual Customers

This credit and fee are applicable to Customers when BPA is remarketing their Tier 2 rate purchase amounts pursuant to section 10 of the CHWM Contract.

(a) Tier 2 Remarketing Rate

(1) For Load Following Customers

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	27.47
2017	29.63

(2) For Slice/Block and Block Customers

After notice is provided by the Slice/Block or Block Customer, the rate shall be the flat annual equivalent market price forecast for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities.

(b) Tier 2 Remarketing Billing Determinant

For each applicable Tier 2 rate, the billing determinant is (i) the Customer's contracted annual Tier 2 amount at such rate plus real power losses, less (ii) the Customer's annual Tier 2 load at such rate plus real power losses.

(c) Tier 2 Remarketing Credit

For each Customer, the Tier 2 Remarketing credit is calculated by multiplying the applicable Tier 2 Remarketing Rate and the Tier 2 Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) Tier 2 Remarketing Fee

The fee for remarketing Customers' Tier 2 amounts is zero in FY 2016–2017.

2. Non-Federal Resource with DFS Remarketing

This credit and fee are applicable to Customers when BPA is remarketing their non-Federal resources to which DFS applies, pursuant to section 10 of the CHWM Contract.

(a) DFS Remarketing Rate

For each fiscal year, the DFS Remarketing rate shall be:

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	27.47
2017	29.63

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the billing determinant is (i) the Customer’s total non-Federal resource, less (ii) the amount of the Customer’s non-Federal resource needed to meet Above-RHWM Load, as reflected in the Customer’s CHWM Contract Exhibit A, when updated.

(c) DFS Remarketing Credit

For each Customer, the DFS Remarketing credit is calculated by multiplying the applicable DFS Remarketing Rate and the DFS Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) DFS Remarketing Fee

The fee for remarketing a Customer’s non-Federal resource with DFS amounts is zero in FY 2016–2017.

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are determined pursuant to the definition of Residential Load in section 2 of the 2012 REP Settlement and are shown in Table E below.

**Table E
Residential Load (in kWh)**

<i>Month</i>	<i>Avista</i>	<i>Idaho</i>	<i>NorthWestern</i>
October	254,399,773	449,427,220	47,071,049
November	286,391,298	432,485,411	51,348,636
December	420,321,296	571,412,065	68,143,968
January	454,730,338	643,022,303	72,747,394
February	426,955,167	646,777,473	66,539,420
March	374,469,095	501,437,402	62,909,111
April	309,851,068	425,493,790	53,084,633
May	274,085,810	459,557,161	48,413,769
June	243,613,640	528,686,504	47,926,071
July	262,544,433	663,892,216	52,069,034
August	303,039,692	747,533,897	55,694,016
September	286,937,433	693,475,174	52,850,224

<i>Month</i>	<i>PacifiCorp</i>	<i>Portland General</i>	<i>Puget Sound</i>
October	583,749,004	578,537,273	766,468,762
November	657,133,518	649,912,673	940,067,549
December	987,429,612	928,228,261	1,271,040,279
January	1,055,914,437	988,358,352	1,383,344,090
February	886,730,182	869,970,113	1,269,404,468
March	755,575,589	755,894,636	1,157,391,506
April	642,732,915	658,188,759	1,009,262,594
May	619,364,358	609,487,580	849,358,465
June	666,920,994	577,985,696	731,718,254
July	707,544,710	640,287,504	748,803,915
August	768,697,230	681,444,938	760,883,048
September	674,001,977	661,683,744	729,693,356

These loads are applicable to each year of the rate period, FY 2016 and FY 2017, and are established pursuant to the 2012 REP Settlement Agreement, Contract No. 11PB-12322.

T. Residential Exchange Program 7(b)(3) Surcharge Adjustment

1. ASC Adjustment

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-16 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3) Surcharge is displayed in the table in section 6.1 of the PF-16 rate schedule and is subject to modification under this GRSP.

In implementing the REP, BPA has identified circumstances where a utility's ASC may be modified during the BPA rate period (*e.g.*, new resource additions, new NLSLs). Subject to limitations in the 2008 ASC Methodology, when BPA modifies a utility's ASC during a BPA rate period, the modified ASC shall be effective on the date specified in BPA's notice to the participating utility confirming the modification of its ASC. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in section 6.1 of the PF-16 rate schedule, BPA shall adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges shall be accomplished by substituting all modified ASCs and recomputing the rates in section 6.1 of the PF-16 rate schedule. This recomputation shall be accomplished by:

- Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to \$/MWh).
- Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-16 7(i) proceeding.
- Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.
- Summing the unconstrained benefits for each participant to compute total unconstrained benefits.
- Computing the difference between the total unconstrained benefits and \$437,978,501 (the total REP benefits adopted for the two-year rate period in the BP-16 7(i) proceeding).
- Allocating the computed difference to participants such that the first \$153,075,234 (the total REP Refund Amounts for the two-year rate period) is allocated only to the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.
- Recomputing the IOU adjustments specified in section 6.2 of the 2012 REP Settlement.
- Dividing the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and adding each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Table 2.4.12 of the Power Rates Study Documentation, BP-16-FS-BPA-01A. This table shall be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges shall take effect on the day that the utility's modified ASC takes

effect. This adjustment shall occur as frequently as ASCs are modified during the two-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges shall be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program Web site.

2. Change in Service Territory Due to Annexation or Load Transfer

Should an REP-participating utility lose or gain load through an annexation or other transfer of load, the total REP benefits of \$437,978,501 in the 7(b)(3) Surcharge calculation in section 1 above will be subject to change. If load is transferred from a participating utility to a preference Customer, resulting in an increase in PF preference load on BPA, and thereby increasing BPA's expenses, then the reduction in REP benefits to the REP-participating IOU will reduce the \$437,978,501 by the same amount. If the load is transferred from a participating utility to another Customer such that BPA expenses are not increased due to the transferred load, then the \$437,978,501 will not be reduced. The \$437,978,501 cannot be increased through a transfer of load.

U. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA Web site.

1. Diurnal Flattening Service Charges, Resource Shaping Charge, and Resource Shaping Charge Adjustment

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service. Unless stated otherwise, the resource amounts used in these calculations are either (1) generation amounts specified in the Customer's CHWM Contract Exhibit A (Exhibit A amounts); or (2) planned generation amounts based on hourly generation from the most recent historical year specified in Exhibit D (Exhibit D amounts).

DFS shall apply to the non-Federal resource the Customer is applying to its load and any portion of the resource remarketed by BPA.

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's Rate Analysis Model calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of planned

generation in excess of average monthly/diurnal Exhibit D amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in section 1(c) below. The monthly/diurnal results are summed for the year and divided by the total planned energy from the Exhibit D amounts to calculate the DFS energy rate.

(2) DFS Energy Billing Determinant

The DFS energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag.

(3) Calculation of DFS Energy Charge

For each resource, the DFS energy charge is calculated by multiplying the DFS energy rate by the DFS energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 demand rates shown in section 2.1.2.1 of the PF-16 rate schedule.

(2) DFS Capacity Billing Determinant

The billing determinant is the difference between the resource's monthly average HLH Exhibit D amounts in one year and the calculated monthly firm capacity of the resource.

The RSS module of BPA's Rate Analysis Model calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) Calculation of DFS Capacity Charge

For each resource, the DFS Capacity charge is the lesser of:

(1) the annual sum of (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants;

or

(2) the annual average Exhibit D amount multiplied by the sum of the monthly PF Tier 1 demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the Customer's CHWM Contract. This charge is take-or-pay, such that if a Customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(c) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in section 2.1.3.1 of the PF-16 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the annual average Exhibit A amounts for the same year. Generally, the Resource Shaping charge does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS is provided to a resource to which RRS also applies, the billing determinant for each resource is the difference between (i) the planned monthly/diurnal generation from Exhibit D amounts and (ii) the sum of the annual average Exhibit A amounts and Resource Remarketed Amounts in Exhibit D for the same year.

(3) Calculation of Resource Shaping Charge

For each resource, the Resource Shaping Charge is calculated by multiplying the Resource Shaping Rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies only in one fiscal year) to calculate a flat monthly charge.

(d) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS,

planned outage replacement, economic dispatch, and unauthorized increases (UAI) in the determination of actual generation.

(3) Calculation of Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is calculated by multiplying the Resource Shaping Charge Adjustment Rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

2. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following Customer that dedicates the entire output of a hydroelectric Existing Resource with a credit for the energy produced by that resource that is in excess of the amounts specified in the CHWM Contract Exhibit A (Exhibit A amounts) and a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal generation from Exhibit A amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

(3) Calculation of SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is calculated by multiplying the SCS energy rate by the SCS energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the Customer will receive a credit. If the actual generation is less than the Exhibit A amount, the Customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 demand rate shown in section 2.1.2.1 of the PF-16 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

(3) Calculation of SCS Administrative Charge

For each resource, the SCS Administrative Charge is calculated by multiplying the SCS Administrative Rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the Customer’s CHWM Contract.

3. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to Customers that have a qualifying resource that experiences a forced outage. Unless stated otherwise, the resource amounts used in these calculations are those specified in the Customer’s CHWM Contract Exhibit D (Exhibit D amounts) and are planned generation amounts based on hourly generation from the most recent historical year.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant, section 1(b)(2).

(3) Calculation of FORS Capacity Charge

For each resource, the FORS Capacity Charge is calculated by multiplying the FORS Capacity Rate and the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the Customer's CHWM Contract. This charge is take-or-pay, so that if a Customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement) during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

The FORS energy billing determinant is the total actual replacement generation a resource requires to meet the planned generation amount specified in Exhibit D of the Customer's CHWM Contract, subject to the FORS energy limits specified therein.

(3) Calculation of FORS Energy Charge

For each resource, the monthly FORS energy charge is calculated by multiplying the FORS energy rate by the FORS energy billing determinant.

4. Transmission Scheduling Service Charge and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the Customer. Transmission Curtailment Management Service (TCMS) is a feature of TSS under which BPA provides

either replacement transmission or power to Customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) TSS Charge

(1) TSS Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2016	0.14
2017	0.14

(2) TSS Billing Determinant

The TSS billing determinant is the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract. When TSS is provided to a resource to which RRS also applies, the TSS billing determinant for each resource is (i) the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract, plus (ii) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS Charge

For each eligible resource, the TSS Charge is calculated by multiplying the TSS Rate and the TSS billing determinant for each month of the rate period (or an individual fiscal year if this service applies only in one fiscal year). The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge. The charge is subject to a cap (not including OATI registration fee recovery adjustments described below). Charges for Specified Resources are capped such that if the annual cost to the Customer using the TSS rate exceeds \$978/month, then the monthly charge is capped at \$978/month. Charges for Unspecified Resource Amounts are capped such that if the annual cost to the Customer using the TSS rate exceeds \$2,934/month, then the monthly charge is capped at \$2,934/month.

For each TSS Customer, BPA will determine the number of resources receiving TSS. Then the \$200 annual OATI registration fee is applied evenly across those resources and divided by 12 months in the applicable fiscal years of the rate period.

(b) TCMS Charge if Replacement Power is Provided

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) Calculation of TCMS Charge

For each eligible resource, the TCMS Charge is calculated by multiplying the TCMS Rate and the TCMS billing determinant for each hour of the month.

(c) TCMS Charge if Alternative Transmission is Provided

When replacement Point-to-Point transmission is used to deliver the Customer's eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

5. Grandfathered Generation Management Service (GMS) Fee

GMS allows a Load Following Customer that dedicated the entire output of an Existing Resource that received GMS during Subscription to run that resource against load and offset its Tier 1 Load.

(a) GMS Reservation Rate

The rate is the monthly PF Tier 1 demand rate shown in section 2.1.2 of the PF rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.U.1.b.

(c) Calculation of GMS Reservation Fee

For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation rate and the GMS Reservation billing determinant for each month. The sum

of the values is divided by 12 to calculate a flat monthly charge. The GMS Reservation Fee will be specified in Exhibit D of the Customer's CHWM Contract.

6. Resource Remarketing Service (RRS) Credits

RRS is an optional service to provide a remarketing credit to Customers that have a qualifying non-Federal resource to which DFS applies that is expected to generate more than a Customer's Above-RHWM load. The non-Federal resource amounts used in these calculations are those specified in the Customer's CHWM Contract Exhibit D RRS section (Exhibit D RRS amounts).

(a) RRS Credit

(1) RRS Rate

For each non-Federal resource, the rate shall be the flat annual equivalent of the PF Load Shaping rates.

(2) RRS Billing Determinant

For each non-Federal resource, the billing determinant is the Exhibit D RRS amount.

(3) Calculation of RRS Credit

For each non-Federal resource, the RRS Credit is calculated by multiplying the RRS Rate and the RRS billing determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit.

(b) RRS Fee

The fee for providing RRS to Customers is determined on a case-by-case basis.

V. RHW M Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in section 2.1.3.2 of the PF-16 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHW M Augmentation. The RT1SC values for the FY 2016–2017 rate period are shown in Table F below.

**Table F
FY 2016-2017 RHW M Tier 1 System Capability**

<i>Month</i>	<i>RT1SC in kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	3,033,357,382	1,728,132,377
November	3,576,839,287	2,163,004,091
December	3,451,735,558	2,138,430,302
January	2,988,470,682	1,862,356,187
February 2016	2,740,931,192	1,640,490,262
February 2017	2,629,201,832	1,584,625,582
March	3,164,137,550	1,926,178,132
April	2,630,827,097	1,606,778,928
May	4,305,965,964	2,391,345,962
June	3,472,759,522	1,965,644,165
July	3,230,114,832	1,728,434,439
August	3,455,063,061	1,756,385,225
September	2,697,717,993	1,684,318,306

W. Slice True-Up Adjustment

Slice Customers shall have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as BPA’s audited actual financial data are available (usually in November). See TRM section 2.7, BP-12-A-03.

1. Calculation of the Annual Composite Cost Pool True-Up

(a) Calculation of the Slice True-Up Adjustment Charge for the Composite Cost Pool

Following the end of each fiscal year of the rate period, BPA shall:

- (1) subtract:
 - (i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period,

from

- (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;
- (2) divide the difference determined in (1) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM section 5.1.1 and the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following Customers; and
- (3) multiply the dollar amount in (2) above by each Slice Customer's Slice percentage for the applicable fiscal year.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. Included in these adjustments and credits are the actual Firm Surplus and Secondary Adjustment from Unused RHW and the actual DSI Revenue Credit described in (b) and (c) below.

(b) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHW

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHW for the applicable fiscal year shall be calculated as the sum of:

- (1) the forecast Firm Surplus and Secondary Adjustment from Unused RHW for the applicable fiscal year developed in the BP-16 7(i) process; and
- (2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year and is equal to the forecast sum of TOCAs for Slice/Block and Block Customers, adjusted

based on the Annual Net Requirement process in accordance with TRM section 5.1.1. For Load Following Customers, sum of actual TOCAs is adjusted based on TRM section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-16 Composite Customer rate.

and

- (3) the Change in Unused RHW M Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHW M Revenue = (Actual Unused RHW M – Forecast Unused RHW M) × 32.67 mills/kWh.

Actual Unused RHW M = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHW M Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year)

Forecast Unused RHW M = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHW M Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(c) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year shall be calculated as the sum of:

- (1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-16 7(i) process;
- (2) (i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* (ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by –17.54 mills/kWh;
and
- (3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues shall be obtained from BPA data sources

–17.54 mills/kWh is calculated by the equation:

$$\text{PFMEES} - 8.93 \text{ mills/kWh}$$

Where:

PFMEES is the PF Merged Equivalent Energy Scalar of –8.61 mills/kWh and is subject to the CRAC, the DDC, and the NFB Emergency Surcharge.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table H) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM section 2.7.2, BPA shall:

- (a) subtract:
 - (1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period
 - from
 - (2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;
 - and
- (b) for each Slice Customer, multiply the resulting difference from (a) above by the ratio of (i) the Customer's Slice percentage for the fiscal year in Exhibit K of the Slice/Block Contract to (ii) the sum of all Customers' Slice percentages for the fiscal year in all Exhibit K of the Slice/Block CHWM Contracts.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

Table G
Composite Cost Pool True-Up Table

	Actual Data (\$000)	FY 2016 forecast (\$000)	FY 2017 forecast (\$000)
1 Operating Expenses			
2 Power System Generation Resources			
3 Operating Generation			
4 COLUMBIA GENERATING STATION (WNP-2)		\$ 262,948	\$ 322,473
5 BUREAU OF RECLAMATION		\$ 156,818	\$ 158,121
6 CORPS OF ENGINEERS		\$ 243,885	\$ 250,981
7 LONG-TERM CONTRACT GENERATING PROJECTS		\$ 22,303	\$ 17,034
8 Sub-Total		\$ 685,954	\$ 748,609
9 Operating Generation Settlement Payment and Other Payments			
10 COLVILLE GENERATION SETTLEMENT		\$ 19,323	\$ 19,651
11 SPOKANE LEGISLATION PAYMENT		\$ -	\$ -
12 Sub-Total		\$ 19,323	\$ 19,651
13 Non-Operating Generation			
14 TROJAN DECOMMISSIONING		\$ 800	\$ 800
15 WNP-1&3 DECOMMISSIONING		\$ 800	\$ 1,063
16 Sub-Total		\$ 1,600	\$ 1,863
17 Gross Contracted Power Purchases			
18 PNCA HEADWATER BENEFITS		\$ 3,000	\$ 3,000
19 OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		\$ -	\$ -
20 Sub-Total		\$ 3,000	\$ 3,000
21 Bookout Adjustment to Power Purchases (omit)			
22 Augmentation Power Purchases (omit - calculated below)			
23 AUGMENTATION POWER PURCHASES		\$ -	\$ -
24 Sub-Total		\$ -	\$ -
25 Exchanges and Settlements			
26 RESIDENTIAL EXCHANGE PROGRAM (REP) (support costs included in support below)		\$ 218,976	\$ 219,003
27 OTHER SETTLEMENTS		\$ -	\$ -
28 Sub-Total		\$ 218,976	\$ 219,003
29 Renewable Generation			
30 RENEWABLES (excludes KIII)		\$ 30,939	\$ 31,483
31 Sub-Total		\$ 30,939	\$ 31,483
32 Generation Conservation			
33 CONSERVATION ACQUISITION		\$ 101,932	\$ 104,702
34 LOW INCOME WEATHERIZATION & TRIBAL		\$ 5,336	\$ 5,422
35 ENERGY EFFICIENCY DEVELOPMENT		\$ 15,000	\$ 7,000
36 DR & SMART GRID		\$ 1,245	\$ 1,245
37 LEGACY		\$ 605	\$ 605
38 MARKET TRANSFORMATION		\$ 12,531	\$ 12,691
39 Sub-Total		\$ 136,649	\$ 131,665
40 Power System Generation Sub-Total		\$ 1,096,440	\$ 1,155,273
41			
42 Power Non-Generation Operations			
43 Power Services System Operations			
44 EFFICIENCIES PROGRAM		\$ -	\$ -
45 INFORMATION TECHNOLOGY		\$ 5,805	\$ 5,910
46 GENERATION PROJECT COORDINATION		\$ 7,735	\$ 7,845
47 SLICE IMPLEMENTATION		\$ 1,101	\$ 1,131
48 Sub-Total		\$ 14,642	\$ 14,886
49 Power Services Scheduling			
50 OPERATIONS SCHEDULING		\$ 10,307	\$ 10,496
51 OPERATIONS PLANNING		\$ 7,100	\$ 7,255
52 Sub-Total		\$ 17,406	\$ 17,751
53 Power Services Marketing and Business Support			
54 POWER R&D		\$ 6,033	\$ 6,046
55 SALES & SUPPORT		\$ 22,139	\$ 24,854
56 STRATEGY, FINANCE & RISK MGMT (REP support costs included here)		\$ 22,538	\$ 22,166
57 EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)		\$ 4,326	\$ 4,402
58 CONSERVATION SUPPORT		\$ 9,456	\$ 9,731
59 Sub-Total		\$ 64,494	\$ 67,199
60 Power Non-Generation Operations Sub-Total		\$ 96,542	\$ 99,836
61 Power Services Transmission Acquisition and Ancillary Services			
62 TRANSMISSION and ANCILLARY Services - System Obligations		\$ 35,815	\$ 35,073
63 3RD PARTY GTA WHEELING		\$ 63,567	\$ 76,521
64 POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)		\$ -	\$ -
65 TRANS ACQ GENERATION INTEGRATION		\$ 12,142	\$ 12,074
66 TELEMETERING/EQUIP REPLACEMT		\$ -	\$ -
67 Power Services Trans Acquisition and Ancillary Serv Sub-Total		\$ 111,524	\$ 123,668
68 Fish and Wildlife/USF&W/Planning Council/Environmental Req			
69 Fish & Wildlife		\$ 267,000	\$ 274,000
70 USF&W Lower Snake Hatcheries		\$ 32,303	\$ 32,949
71 Planning Council		\$ 11,236	\$ 11,446
72 Environmental Requirements		\$ -	\$ -
73 Fish and Wildlife/USF&W/Planning Council Sub-Total		\$ 310,539	\$ 318,395

**Table G, continued
Composite Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2016 forecast (\$000)	FY 2017 forecast (\$000)
74	BPA Internal Support		
75	Additional Post-Retirement Contribution	\$ 19,143	\$ 19,478
76	Agency Services G&A (excludes direct project support)	\$ 53,138	\$ 55,168
77	BPA Internal Support Sub-Total	\$ 72,281	\$ 74,646
78	Bad Debt Expense	\$ -	\$ -
79	Other Income, Expenses, Adjustments	\$ (25,896)	\$ (61,926)
80	Expense Offset	\$ (71,542)	\$ (67,685)
81	Non-Federal Debt Service		
82	Energy Northwest Debt Service		
83	COLUMBIA GENERATING STATION DEBT SVC	\$ 100,810	\$ 127,466
84	WNP-1 DEBT SVC	\$ 258,325	\$ 201,804
85	WNP-3 DEBT SVC	\$ 225,942	\$ 256,332
86	EN RETIRED DEBT	\$ -	\$ -
87	Sub-Total	\$ 585,077	\$ 585,602
88	Non-Energy Northwest Debt Service		
89	CONSERVATION DEBT SVC	\$ -	\$ -
90	COWLITZ FALLS DEBT SVC	\$ 7,300	\$ 7,303
91	NORTHERN WASCO DEBT SVC	\$ 1,931	\$ 1,935
92	Sub-Total	\$ 9,231	\$ 9,237
93	Non-Federal Debt Service Sub-Total	\$ 594,308	\$ 594,839
94	Depreciation	\$ 140,201	\$ 143,468
95	Amortization	\$ 82,350	\$ 85,034
96	Total Operating Expenses	\$ 2,406,748	\$ 2,465,550
97			
98	Other Expenses		
99	Net Interest Expense	\$ 194,389	\$ 195,296
100	LDD	\$ 39,865	\$ 40,464
101	Irrigation Rate Discount Costs	\$ 22,146	\$ 22,146
102	Sub-Total	\$ 256,400	\$ 257,906
103	Total Expenses	\$ 2,663,149	\$ 2,723,456
104			
105	Revenue Credits		
106	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	\$ 115,750	\$ 115,750
107	Downstream Benefits and Pumping Power revenues	\$ 17,219	\$ 17,219
108	4(h)(10)(c) credit	\$ 91,107	\$ 87,786
109	Colville and Spokane Settlements	\$ 4,600	\$ 4,600
110	Energy Efficiency Revenues	\$ 15,000	\$ 7,000
111	Large Project Revenues	\$ -	\$ -
112	Miscellaneous revenues	\$ 5,750	\$ 5,800
113	Renewable Energy Certificates	\$ 1,151	\$ 648
114	Pre-Subscription Revenues (Big Horn/Hungry Horse)	\$ 2,036	\$ 1,506
115	Net Revenues from other Designated BPA System Obligations (Upper Baker)	\$ 457	\$ 466
116	WNP-3 Settlement revenues	\$ 34,537	\$ 34,537
117	RSS Revenues	\$ 3,049	\$ 3,468
118	Firm Surplus and Secondary Adjustment (from Unused RHWM)	\$ 5,991	\$ 2,744
119	Balancing Augmentation Adjustment	\$ 1,445	\$ 10,543
120	Transmission Loss Adjustment	\$ 29,120	\$ 29,437
121	Tier 2 Rate Adjustment	\$ 725	\$ 835
122	NR Revenues	\$ 1	\$ 1
123	Total Revenue Credits	\$ 327,937	\$ 322,340
124			
125	Augmentation Costs (not subject to True-Up)		
126	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	\$ 12,493	\$ 12,603
127	Augmentation Purchases	\$ -	\$ 20,960
128	Total Augmentation Costs	\$ 12,493	\$ 33,564
129			
130	DSI Revenue Credit		
131	Revenues 91 aMW @ IP rate	\$ 33,560	\$ 33,469
132	Total DSI revenues	\$ 33,560	\$ 33,469
133			
134	Minimum Required Net Revenue Calculation		
135	Principal Payment of Fed Debt for Power	\$ 94,697	\$ 109,429
136	Irrigation assistance	\$ 61,066	\$ 51,482
137	Sub-Total	\$ 155,763	\$ 160,911
138	Depreciation	\$ 140,201	\$ 143,468
139	Amortization	\$ 82,350	\$ 85,034
140	Capitalization Adjustment	\$ (45,937)	\$ (45,937)
141	Bond Premium Amortization	\$ -	\$ -
142	PGE WNP3 Settlement	\$ (3,524)	\$ (3,524)
143	Prepay Revenue Credits	\$ (30,600)	\$ (30,600)
144	Non-Federal Interest (Prepay)	\$ 13,273	\$ 12,469
145	Sub-Total	\$ 155,763	\$ 160,911
146	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	\$ (0)	\$ 0
147	Minimum Required Net Revenues	\$ -	\$ 0
148			
149	Annual Composite Cost Pool (Amounts for each FY)	\$ 2,314,145	\$ 2,401,211
150			
151	SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL		
152	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)		
153	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)		
154	TRUE-UP ADJUSTMENT CHARGE BILLED (26.61865 percent)		

**Table H
Slice Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2016 forecast (\$000)	FY 2017 forecast (\$000)
1 Slice Expenses			
2			
3			
4 Total Slice Expenses		\$ -	\$ -
5			
6 Slice Credits			
7			
8 Total Slice Credits		\$ -	\$ -
9			
10 Annual Slice Cost Pool (Amounts for each FY)		\$ -	\$ -
11			
12 SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL			
13 TRUE UP AMOUNT (Diff. between actual Slice Cost Pool and forecast Slice COST Pool for applicable FY)			
14			
15 TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)			

X. Tier 2 Rate TCMS Adjustment

When BPA provides replacement power during a transmission event, a TCMS adjustment will be applied to Customers’ bills if they purchase power at the applicable Tier 2 rate. The megawatthours of replacement power will be multiplied by the applicable Powerdex Mid-C hourly index price (or its replacement) for the hour(s) the event occurred. If a Mid-C price is less than zero, the TCMS Adjustment rate will be zero for that hour. The sum of this calculation every month is the Tier 2-related TCMS cost. Each Tier 2 rate Customer’s TCMS adjustment will be the Customer’s share of the Tier 2-related TCMS cost allocated by total applicable Tier 2 rate sales.

Y. TOCA Adjustment

For each Customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-16 7(i) process and will be made available to the Customer prior to October 1, 2015. A Customer’s TOCA for a fiscal year will be revised only as specified below.

The Customer’s Adjusted TOCA will be the billing determinant for the Composite, Slice, and Non-Slice Customer charges for the relevant fiscal year. No other Customer’s TOCA shall be affected by this TOCA adjustment.

If a TOCA is modified after the October power bill is issued for the fiscal year that the modified TOCA applies, the Customer will be billed retroactively to October 1 of that fiscal year through a one-time billing adjustment. The billing adjustment will be calculated as (i) the sum of the amount billed for the months prior to any mid-year TOCA adjustment minus (ii) the sum of the amount that should have been billed for those same months with the mid-year adjusted TOCA. A positive calculation is a credit to the Customer, and a negative calculation is a charge to the Customer.

1. Load Following Customers

If there is substantial reason for BPA to believe that the Customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the RHW process for the applicable year, BPA shall calculate an Adjusted TOCA for that Load Following Customer using an updated estimate of the Customer's Actual Annual Tier 1 Load in place of the Customer's Forecast Net Requirement, as follows:

$$\frac{\text{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-16 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-16 7(i) process.

The Load Following Customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block Customer in three circumstances:

- (a) If the Customer's Annual Net Requirement is less than its RHW and differs from the Forecast Net Requirement used in the BP-16 7(i) process, the Customer's TOCA shall be recalculated for that fiscal year using the Customer's Annual Net Requirement.
- (b) If the Customer's Annual Net Requirement equals or exceeds its RHW, and its Forecast Net Requirement used in the BP-16 7(i) process is less than its RHW, then the Customer's TOCA shall be recalculated for that fiscal year using the Customer's RHW.
- (c) If a Customer's Annual Net Requirement changes within a fiscal year due to a change in the Customer's Specified Resource amounts within a fiscal year, then the Customer's TOCA shall be recalculated.

Z. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2015, that results in an unanticipated increase in a Customer's load placed on BPA during the FY 2016–2017 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a Customer that adds load through retail access, including load that was once served by the Customer and returns under retail access. ULS that is used for replacement of a Customer's new Specified Resource is

available only on a temporary basis for the FY 2016–2017 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of Unanticipated Load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-16, Unanticipated Load is:

- Load of a New Public (Load Following Customers only)
- Load annexed from investor-owned utilities by a Public (Load Following Customers only)

Under NR-16, Unanticipated Load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-16, Unanticipated Load is negotiated on a case-by-case basis.

BPA also will review annexations of load between public utility Customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered Unanticipated Load.

To start service for Unanticipated Load, the Customer must notify BPA three months in advance of the requested service date for load amounts up to 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for Unanticipated Load, the Customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the Customer's contract for Unanticipated Load Service or the conclusion of the rate period on September 30, 2017, whichever occurs first. ULS is a temporary service and may be adjusted annually. For load annexed from investor-owned utilities by a Public (Load Following Customers only) served under PF-16 and for resource replacement of a Public Load Following Customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 (one) aMW per year. These loads will be included in the Customer's Actual Hourly Tier 1 Loads and Actual Monthly/Diurnal Tier 1 Load for billing purposes. Any Unanticipated Load Service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable

diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	\$27.86	\$23.75
November	\$28.56	\$24.48
December	\$29.22	\$24.82
January	\$30.02	\$25.03
February	\$29.65	\$24.68
March	\$25.38	\$22.07
April	\$24.36	\$21.04
May	\$22.10	\$17.53
June	\$23.15	\$17.11
July	\$27.43	\$21.58
August	\$30.30	\$24.41
September	\$31.75	\$25.70

(2) Energy Billing Determinant

The energy billing determinant shall be the total amount of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in section 2.1.2.1 of the PF-16 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant shall be the lesser of (1) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month or (2) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable

diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	76.33	72.22
November	77.03	72.95
December	77.69	73.29
January	78.49	73.50
February	78.12	73.15
March	73.85	70.54
April	72.83	69.51
May	70.57	66.00
June	71.62	65.58
July	75.90	70.05
August	78.77	72.88
September	80.22	74.17

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in section 2.2 of the NR-16 rate schedule.

(2) Demand Billing Determinant

The Demand billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated NR Hourly Load in a month.

4. Unanticipated Load Service Charge Under the FPS-16 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of (1) the Resource Replacement rate for the applicable diurnal period (shown in the table below), or (2) the applicable diurnal period forecast market price for purchased

power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Resource Replacement Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	\$27.86	\$23.75
November	\$28.56	\$24.48
December	\$29.22	\$24.82
January	\$30.02	\$25.03
February	\$29.65	\$24.68
March	\$25.38	\$22.07
April	\$24.36	\$21.04
May	\$22.10	\$17.53
June	\$23.15	\$17.11
July	\$27.43	\$21.58
August	\$30.30	\$24.41
September	\$31.75	\$25.70

(2) Energy Billing Determinant

The energy billing determinant is the total of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.02
November	10.27
December	10.51
January	10.79
February	10.66
March	9.13
April	8.76
May	7.95
June	8.33
July	9.87
August	10.90
September	11.42

(2) Demand Billing Determinant

The Demand billing determinant is the highest maximum unanticipated Resource Replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated Resource Replacement load in a month.

AA. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any Customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during an HLH billing hour that exceeds the amount of demand the Customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand rate.

The billing determinant for the UAI demand charge shall be equal to the Customer's single highest HLH demand that is in excess of the Customer's contractual demand entitlement.

For a Load Following Customer, the demand in excess of its demand entitlement shall be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the Customer's CHWM Contract Exhibit A amount or Exhibit D amount, whichever is applicable.

For a Block Customer or for the Block portion of the Slice/Block product, the Customer's contractual demand entitlement shall be the sum of its Tier 1 and Tier 2 HLH purchase amounts, in accordance with Exhibit C of the CHWM Contract.

For a Slice Customer, the Slice portion of the Slice/Block product will be subject to a demand UAI if the Slice demand is in excess of the Slice entitlement during the peak Delivery Request (Right To Power) HLH of a month. The Slice demand in excess of the Slice entitlement is measured by subtracting (i) the largest final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of a month from (ii) the hourly amount of Slice power delivery (tagged + untagged energy) from BPA for the same HLH of the same month, as such terms are defined in the Slice/Block CHWM Contract.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the Customer is contractually entitled to take during a diurnal billing period shall be billed the greater of:

- (a) 150 mills/kWh;

or

(b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price index expires, the index will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade between October 1, 2015, and September 30, 2017.

This page intentionally left blank.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in section 4 of the Block and Slice/Block CHWM Contracts.

2. Capacity Without Energy

Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. The notice provision may be automated, such as Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity product. No energy is sold with Capacity Without Energy; any energy delivered when the capacity contract is exercised will be returned or paid for under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when capacity rights are exercised.

3. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible Customers under the Priority Firm Power (PF-16), New Resources Firm Power (NR-16), and Firm Power Products and Services (FPS-16) rate schedules. Such power is not available under the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

- (a) Power sold for construction is to be used in the construction of the project.
- (b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project on-line and to ensure that the project is working properly.
- (c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.
- (d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. Energy Shaping Service for NLSL

Energy Shaping Service is an optional service for Load Following Customers serving a New Large Single Load (NLSL) with a non-Federal resource. ESS includes a capacity component and an energy component. These services shape a Customer's resource energy and capacity output amounts to the actual load of a NLSL.

5. Firm Requirements Power

Firm Requirements Power is Federal power that BPA makes continuously available to a Customer to meet BPA's obligations to the Customer under section 5(b) of the Northwest Power Act.

6. Forced Outage Reserve Service (FORS)

As defined in the TRM, FORS is a service that provides an agreed-upon amount of capacity and energy to load during the forced outages of a qualifying resource.

7. General Transfer Agreement Service

Allows BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements to receive power and energy over investor-owned or public utilities' systems.

8. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make available to a DSI Customer subject to the terms of the DSI Customer's power sales contract with BPA.

9. Large Project Program (LPP)

The Large Project Program was established in the BPA Revised Energy Efficiency Post-2011 Implementation Program, and makes available at BPA's discretion monies for the acquisition of conservation above and beyond the Energy Efficiency Incentives program. The costs of LPP acquisitions are recovered through a special rate provision, the Large Project Targeted Adjustment Charge.

10. Load Following Product

As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the Customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

11. Load Shaping

BPA provides Load Shaping to Customers with CHWM Contracts purchasing the Load Following Product, the Block Product, or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a Customer's Actual Monthly/Diurnal Tier 1 Load.

12. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

- (a) for any NLSL, as defined in the Northwest Power Act;
- (b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

NR is to be used to meet the Customer's firm power load within the Pacific Northwest. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

13. NR Resource Flattening Service (NRFS)

NR Resource Flattening Service (NRFS) is applicable to Load Following Customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

14. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program (REP) may purchase PF pursuant to their RPSA or REPSIA with BPA. PF is not available to serve New Large Single Loads. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Customer pursuant to the REP. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible Pacific Northwest utilities at a utility's Average System Cost (ASC). BPA then

offers, in exchange, to “sell” an equivalent amount of electric power to that Customer at BPA’s PF rate applicable to exchanging utilities (PF Exchange rate). The amounts of power purchased and sold are both equal to the utility’s eligible residential and farm load. Benefits must be passed directly to the utility’s residential and farm Customers.

16. Resource Remarketing Service (RRS)

Resource Remarketing Service (RRS) is a service that BPA makes available at its discretion to Load Following Customers where BPA remarkets non-Federal resources on behalf of Customers and provides them with remarketing credits, net of a remarketing fee.

17. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following Customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block and Block Customers contractually dedicate to serving their Total Retail Load. RSS includes: Diurnal Flattening Service, Forced Outage Reserve Service, Grandfathered Generation Management Service, Secondary Crediting Service, Transmission Scheduling Service and Transmission Curtailment Management Service.

18. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the Customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the Customer applies its resource directly to load, and Federal deliveries cover the net load.

19. Slice/Block Product

The Slice/Block Product is the Customer’s purchase obligation under the Slice product and the Block Product to meet the Customer’s regional consumer load obligation under section 3.1 of the Slice/Block CHWM Contract.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the Customer’s Rate Period High Water Mark, as determined in the RHWM Process.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the Customer's electric load (measured in kilowatthours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

- (a) A measure of electric power usage at a Customer's metered point of delivery used in the computation of a Customer's bill.
- (b) As defined in the Tiered Rate Methodology, a unit of measure for sales of a product or service for which a Customer is billed by BPA.

4. Charge

A charge is the product of a billing determinant and a rate.

5. Contract Demand

The Customer's Contract Demand is the maximum amount of capacity that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each Customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the Customer's demand charge billing determinant, as calculated in accordance with TRM section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each Customer in accordance with TRM section 4. For each Customer with a CHWM Contract, the CHWM is used to calculate each Customer's RHWM in the RHWM Process for each applicable rate period. The CHWM Contract specifies the CHWM for each Customer.

9. CHWM Contract

As defined in the TRM, the CHWM Contract is the power sales contract between a Customer and BPA that contains a Contract High Water Mark (CHWM) and under which the Customer purchases power from BPA at rates established by BPA in accordance with the TRM.

10. Customer

Pursuant to the terms of an agreement and applicable rate schedule(s), a Customer is the entity that contracts to pay BPA for providing a product or service.

11. DSI Reserve

A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in GRSP II.F, that is provided by a DSI in a contract with BPA.

12. Energy Efficiency Incentive

The Energy Efficiency Incentive is a funding mechanism that establishes a budget from which BPA funds energy efficiency incentive payments and associated qualified performance payments for Customers with a CHWM Contract.

13. Flat Annual Shape

As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

14. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all hours in the on-peak period – the hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable) – except for the six holidays specified in NERC Standards. See also Light Load Hours definition.

15. Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index

Average HLH (or on-peak) and average LLH (or off-peak) price indices for firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Intercontinental Exchange, Inc.

16. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the hour ending 11 p.m. through the hour ending 6 a.m., Monday through Saturday, and all hours Sunday,

Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

17. Metered Demand

The Metered Demand, in kilowatts, shall be the largest of the 60-minute clock hour integrated demands at which electric energy is delivered to a Customer:

- (a) at each point of delivery for which the Metered Demand is the basis for determination of the measured demand;
- (b) during each time period specified in the applicable rate schedule; and
- (c) during any billing period.

Such largest integrated demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Customer.

18. Metered Energy

The Metered Energy for a Customer shall be the number of kilowatthours recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Customer:

- (a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and
- (b) during any billing period.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer. (As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.)

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of (1) a Customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or (2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to section 5(b) of the Northwest Power Act.

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM section 4.2.1 and expressed in average megawatts, that BPA establishes for each Customer based on the Customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a Customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following Customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block Customers.

24. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the Customer-specific charge or credit as described in TRM section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

25. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

26. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

27. RHWM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHWM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC table of values may be found at GRSP II.V.

28. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM section 5.3.4, that a Customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

29. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a Customer must reshape its HLH energy from its Specified Resources and Unspecified Resource Amounts to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2016–2017 are as follows (HE = Hour Ending):

October – February	HE 8 through HE 10 and HE 18 through HE 20
March – May	HE 7 through HE 12
June – September	HE 13 through HE 18

30. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block Customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the Customer's TOCA Load was delivered in the shape of the RHWM Tier 1 System Capability through such periods.

31. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the Customer charges for each Customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM section 5.1.1. TOCAs are posted on BPA's Web site.

32. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the Customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

33. Total Customer System Peak (CSP or Total CSP)

Total Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

34. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a Customer's electrical system, excluding (i) those loads BPA and the Customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such Customer; and (iii) any loads not on such Customer's electrical system or not within such Customer's service territory, unless specifically agreed to by BPA.

35. Unanticipated Load

Unanticipated Load is any request by a Customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the Customer's load placed on BPA during the ensuing rate period, and (2) was not requested and thus not forecast when setting the rates for that rate period.

36. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a Customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the Customer's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

Appendix A

Residential Exchange Program Settlement Customer Refund Amounts in FY 2016–2017

This page intentionally left blank.

Residential Exchange Program Settlement Customer Refund Amounts in FY 2016–2017

Section 1. Purpose

The Customer Refund Amount in FY 2016–2017 is a credit on a Customer’s power bill pursuant to the 2012 REP Settlement Agreement, Contract No. 11PB-12322 (Settlement). The individual Customer credit is determined in part on the terms of the Settlement and in part on information developed in each rate proceeding.

Section 2. Terms of the Customer Refund Amount

The Customer Refund Amount applies to Customers listed in the table below.

A credit shall appear on the monthly power bills beginning with the month that the rates established in the BP-16 rate proceeding take effect. The total credit for a given fiscal year will be the fiscal year’s Total Refund divided into 12 equal monthly amounts. Monthly amounts shall be rounded to the nearest whole dollar amount on the power bill.

Section 3. Definitions

PF-02 Refund is the portion of the Customer Refund Amount provided pursuant to Exhibit B of the Settlement.

Scaled TOCA is the Customer-specific percentage derived from a Customer’s BP-16 Final Proposal TOCA as adjusted pursuant to section 3.4 of the REP Settlement Agreement.

TOCA Refund is the annual Refund Amount from section 3.2 of the Settlement (\$76,537,617) minus the total annual Customer Specific PF-02 Refund Amount from Exhibit B of the Settlement (\$38,269,000) multiplied by the Scaled TOCA. Thus, $\$76,537,617 - \$38,269,000 = \$38,268,617$, which then is multiplied by the Scaled TOCA.

Total Refund is the sum of the PF-02 Refund Amount and the TOCA Refund Amount.

Section 4. Customer Refund Amounts

As displayed on the following table:

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10005	Alder Mutual	\$3,178	0.0079%	0.0079%	\$3,008	\$3,015	\$6,186	\$6,193
10015	Asotin County PUD #1	\$ -	0.0083%	0.0083%	\$3,176	\$3,158	\$3,176	\$3,158
10024	Benton County PUD #1	\$1,074,609	2.9177%	2.9020%	\$1,116,559	\$1,110,555	\$2,191,168	\$2,185,164
10025	Benton REA	\$365,914	0.9659%	0.9607%	\$369,624	\$367,637	\$735,538	\$733,550
10027	Big Bend Elec Coop	\$180,557	0.8857%	0.8810%	\$338,950	\$337,128	\$519,508	\$517,685
10029	Blachly Lane Elec Coop	\$102,877	0.2550%	0.2536%	\$97,572	\$97,047	\$200,449	\$199,924
10044	Canby, City of	\$146,793	0.2940%	0.2924%	\$112,493	\$111,888	\$259,286	\$258,681
10046	Central Electric Coop	\$400,537	1.1847%	1.1783%	\$453,365	\$450,927	\$853,901	\$851,464
10047	Central Lincoln PUD	\$483,285	2.2378%	2.2316%	\$856,389	\$853,991	\$1,339,673	\$1,337,275
10055	Albion, City of	\$ -	0.0058%	0.0057%	\$2,203	\$2,191	\$2,203	\$2,191
10057	Ashland, City of	\$161,518	0.3049%	0.3033%	\$116,695	\$116,068	\$278,214	\$277,586
10059	Bandon, City of	\$55,554	0.1104%	0.1100%	\$42,259	\$42,086	\$97,813	\$97,640
10061	Blaine, City of	\$60,506	0.1266%	0.1259%	\$48,446	\$48,186	\$108,952	\$108,692
10062	Bonnors Ferry, City of	\$45,589	0.0770%	0.0766%	\$29,467	\$29,308	\$75,055	\$74,897
10064	Burley, City of	\$105,386	0.2010%	0.2005%	\$76,921	\$76,732	\$182,306	\$182,118
10065	Cascade Locks, City of	\$17,913	0.0320%	0.0318%	\$12,237	\$12,179	\$30,150	\$30,092
10066	Centralia, City of	\$164,230	0.3528%	0.3509%	\$134,995	\$134,269	\$299,225	\$298,500
10067	Cheney, City of	\$108,606	0.2289%	0.2277%	\$87,611	\$87,140	\$196,218	\$195,746
10068	Chewelah, City of	\$ -	0.0381%	0.0379%	\$14,577	\$14,499	\$14,577	\$14,499
10070	Declo, City of	\$ -	0.0052%	0.0052%	\$1,984	\$1,974	\$1,984	\$1,974
10071	Drain, City of	\$19,088	0.0277%	0.0276%	\$10,605	\$10,548	\$29,693	\$29,636
10072	Ellensburg, City of	\$175,179	0.3471%	0.3452%	\$132,835	\$132,121	\$308,014	\$307,300
10074	Forest Grove, City of	\$169,141	0.3862%	0.3841%	\$147,791	\$146,996	\$316,932	\$316,137
10076	Heyburn, City of	\$50,558	0.0697%	0.0693%	\$26,682	\$26,538	\$77,240	\$77,096
10078	McCleary, City of	\$35,576	0.0515%	0.0514%	\$19,717	\$19,662	\$55,293	\$55,238
10079	McMinnville, City of	\$593,568	1.2763%	1.2694%	\$488,413	\$485,787	\$1,081,981	\$1,079,355
10080	Milton, Town of	\$53,707	0.1076%	0.1071%	\$41,189	\$40,967	\$94,896	\$94,674
10081	Milton-Freewater, City of	\$76,961	0.1453%	0.1451%	\$55,598	\$55,544	\$132,559	\$132,505
10082	Minidoka, City of	\$ -	0.0017%	0.0017%	\$637	\$645	\$637	\$645
10083	Monmouth, City of	\$59,603	0.1211%	0.1204%	\$46,325	\$46,076	\$105,928	\$105,679
10086	Plummer, City of	\$28,254	0.0571%	0.0568%	\$21,854	\$21,737	\$50,108	\$49,990
10087	Port Angeles, City of	\$517,172	1.2194%	1.2147%	\$466,664	\$464,847	\$983,837	\$982,019
10089	Richland, City of	\$623,657	1.4988%	1.4907%	\$573,568	\$570,484	\$1,197,225	\$1,194,141
10091	Rupert, City of	\$72,943	0.1364%	0.1356%	\$52,188	\$51,907	\$125,131	\$124,850
10094	Soda Springs, City of	\$ -	0.0430%	0.0425%	\$16,452	\$16,278	\$16,452	\$16,278

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10095	Sumas, Town of	\$23,429	0.0527%	0.0524%	\$20,174	\$20,066	\$43,603	\$43,495
10097	Troy, City of	\$ -	0.0295%	0.0293%	\$11,288	\$11,228	\$11,288	\$11,228
10101	Clallam County PUD #1	\$520,583	1.1004%	1.0945%	\$421,113	\$418,849	\$941,696	\$939,432
10103	Clark County PUD #1	\$2,370,948	4.3314%	4.3267%	\$1,657,562	\$1,655,771	\$4,028,511	\$4,026,720
10105	Clatskanie PUD	\$617,393	1.3437%	1.3365%	\$514,224	\$511,459	\$1,131,617	\$1,128,852
10106	Clearwater Power	\$125,833	0.3382%	0.3378%	\$129,441	\$129,265	\$255,274	\$255,098
10109	Columbia Basin Elec Coop	\$ -	0.1754%	0.1745%	\$67,121	\$66,760	\$67,121	\$66,760
10111	Columbia Power Coop	\$ -	0.0425%	0.0425%	\$16,249	\$16,266	\$16,249	\$16,266
10112	Columbia River PUD	\$265,444	0.8179%	0.8194%	\$312,983	\$313,561	\$578,428	\$579,006
10113	Columbia REA	\$ -	0.5456%	0.5426%	\$208,779	\$207,657	\$208,779	\$207,657
10116	Consolidated Irrigation District #19	\$1,825	0.0029%	0.0029%	\$1,109	\$1,103	\$2,935	\$2,929
10118	Consumers Power	\$246,076	0.6611%	0.6575%	\$252,983	\$251,623	\$499,059	\$497,699
10121	Coos Curry Elec Coop	\$229,267	0.5810%	0.5793%	\$222,337	\$221,709	\$451,604	\$450,976
10123	Cowlitz County PUD #1	\$3,446,817	7.9490%	7.9063%	\$3,041,971	\$3,025,615	\$6,488,788	\$6,472,432
10136	Douglas Electric Cooperative	\$105,338	0.2634%	0.2628%	\$100,818	\$100,555	\$206,156	\$205,893
10142	East End Mutual Electric	\$ -	0.0389%	0.0387%	\$14,886	\$14,806	\$14,886	\$14,806
10144	Eatonville, City of	\$23,238	0.0485%	0.0485%	\$18,553	\$18,555	\$41,792	\$41,793
10156	Elmhurst Mutual P & L	\$ -	0.4651%	0.4641%	\$177,973	\$177,606	\$177,973	\$177,606
10157	Emerald PUD	\$376,548	0.6827%	0.6850%	\$261,244	\$262,159	\$637,792	\$638,707
10158	Energy Northwest	\$20,415	0.0401%	0.0398%	\$15,327	\$15,233	\$35,742	\$35,648
10170	Eugene Water & Electric Board	\$1,490,101	3.4838%	3.4745%	\$1,333,201	\$1,329,650	\$2,823,302	\$2,819,751
10172	U.S. Airforce Base, Fairchild	\$60,465	0.0829%	0.0833%	\$31,721	\$31,872	\$92,186	\$92,338
10173	Fall River Elec Coop	\$152,407	0.4795%	0.4769%	\$183,507	\$182,521	\$335,914	\$334,927
10174	Farmers Elec Coop	\$ -	0.0073%	0.0073%	\$2,808	\$2,793	\$2,808	\$2,793
10177	Ferry County PUD #1	\$67,875	0.1688%	0.1679%	\$64,609	\$64,262	\$132,484	\$132,137
10179	Flathead Elec Coop	\$608,080	2.4146%	2.4016%	\$924,021	\$919,053	\$1,532,101	\$1,527,132
10183	Franklin County PUD #1	\$471,954	1.6985%	1.6894%	\$650,000	\$646,505	\$1,121,954	\$1,118,459
10186	Glacier Elec Coop	\$ -	0.3085%	0.3069%	\$118,074	\$117,439	\$118,074	\$117,439
10190	Grant County PUD #2	\$1,146,092	0.5924%	0.5892%	\$226,696	\$225,477	\$1,372,788	\$1,371,569
10191	Grays Harbor PUD #1	\$736,828	1.8992%	1.8890%	\$726,800	\$722,892	\$1,463,627	\$1,459,719
10197	Harney Elec Coop	\$91,382	0.3293%	0.3276%	\$126,027	\$125,349	\$217,409	\$216,731
10202	Hood River Elec Coop	\$89,783	0.1896%	0.1886%	\$72,554	\$72,164	\$162,337	\$161,947
10203	Idaho County L & P	\$39,010	0.0899%	0.0894%	\$34,416	\$34,231	\$73,425	\$73,240
10204	Idaho Falls Power	\$435,271	1.1515%	1.1453%	\$440,654	\$438,285	\$875,925	\$873,556
10209	Inland P & L	\$ -	1.5594%	1.5510%	\$596,769	\$593,560	\$596,769	\$593,560
10230	Kittitas County PUD #1	\$48,061	0.1404%	0.1397%	\$53,743	\$53,454	\$101,803	\$101,514

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10231	Klickitat County PUD #1	\$219,238	0.5306%	0.5277%	\$203,049	\$201,957	\$422,287	\$421,195
10234	Kootenai Electric Coop	\$ -	0.7382%	0.7342%	\$282,481	\$280,962	\$282,481	\$280,962
10235	Lakeview L & P (WA)	\$261,953	0.4640%	0.4638%	\$177,555	\$177,486	\$439,507	\$439,439
10236	Lane County Elec Coop	\$154,159	0.4004%	0.3984%	\$153,228	\$152,466	\$307,387	\$306,625
10237	Lewis County PUD #1	\$720,554	1.5850%	1.5792%	\$606,550	\$604,357	\$1,327,104	\$1,324,911
10239	Lincoln Elec Coop (MT)	\$ -	0.2007%	0.1994%	\$76,792	\$76,313	\$76,792	\$76,313
10242	Lost River Elec Coop	\$50,765	0.1379%	0.1371%	\$52,762	\$52,478	\$103,527	\$103,243
10244	Lower Valley Energy	\$ -	1.2453%	1.2386%	\$476,554	\$473,992	\$476,554	\$473,992
10246	Mason County PUD #1	\$52,092	0.1301%	0.1294%	\$49,778	\$49,510	\$101,870	\$101,603
10247	Mason County PUD #3	\$544,117	1.1569%	1.1507%	\$442,721	\$440,340	\$986,838	\$984,457
10256	Midstate Elec Coop	\$287,247	0.6641%	0.6635%	\$254,124	\$253,900	\$541,371	\$541,146
10258	Mission Valley	\$ -	0.5399%	0.5445%	\$206,604	\$208,368	\$206,604	\$208,368
10259	Missoula Elec Coop	\$ -	0.3887%	0.3885%	\$148,764	\$148,667	\$148,764	\$148,667
10260	Modern Elec Coop	\$ -	0.3750%	0.3762%	\$143,518	\$143,986	\$143,518	\$143,986
10273	Nespelem Valley Elec Coop	\$35,342	0.0851%	0.0847%	\$32,576	\$32,401	\$67,917	\$67,742
10278	Northern Lights	\$134,905	0.5200%	0.5172%	\$198,999	\$197,929	\$333,903	\$332,833
10279	Northern Wasco County PUD	\$169,186	0.9374%	0.9324%	\$358,730	\$356,801	\$527,916	\$525,987
10284	Ohop Mutual Light Company	\$ -	0.1428%	0.1428%	\$54,645	\$54,666	\$54,645	\$54,666
10285	Okanogan County Elec Coop	\$33,056	0.0944%	0.0940%	\$36,111	\$35,967	\$69,167	\$69,023
10286	Okanogan County PUD #1	\$302,445	0.6645%	0.6609%	\$254,296	\$252,928	\$556,740	\$555,373
10288	Orcas P & L	\$ -	0.3580%	0.3561%	\$137,003	\$136,266	\$137,003	\$136,266
10291	Oregon Trail Coop	\$535,684	1.1367%	1.1399%	\$434,983	\$436,222	\$970,667	\$971,907
10294	Pacific County PUD #2	\$263,432	0.5258%	0.5230%	\$201,213	\$200,131	\$464,645	\$463,563
10304	Parkland L & W	\$ -	0.2027%	0.2025%	\$77,589	\$77,506	\$77,589	\$77,506
10306	Pend Oreille County PUD #1	\$218,512	0.0812%	0.3709%	\$31,060	\$141,930	\$249,572	\$360,442
10307	Peninsula Light Company	\$484,256	1.0419%	1.0363%	\$398,724	\$396,580	\$882,980	\$880,836
10326	U.S. Naval Base, Bremerton	\$216,980	0.4188%	0.4166%	\$160,286	\$159,421	\$377,266	\$376,401
10331	Raft River Elec Coop	\$81,677	0.5093%	0.5106%	\$194,917	\$195,388	\$276,594	\$277,065
10333	Ravalli County Elec Coop	\$ -	0.2680%	0.2665%	\$102,552	\$102,000	\$102,552	\$102,000
10338	Riverside Elec Coop	\$ -	0.0343%	0.0342%	\$13,140	\$13,069	\$13,140	\$13,069
10342	Salem Elec Coop	\$342,469	0.5451%	0.5437%	\$208,619	\$208,068	\$551,088	\$550,537
10343	Salmon River Elec Coop	\$126,695	0.1788%	0.1777%	\$68,421	\$68,018	\$195,116	\$194,713
10349	Seattle City Light	\$2,806,762	7.5830%	7.5422%	\$2,901,906	\$2,886,303	\$5,708,668	\$5,693,065
10352	Skamania County PUD #1	\$110,458	0.2248%	0.2248%	\$86,022	\$86,010	\$196,480	\$196,468
10354	Snohomish County PUD #1	\$4,394,837	11.1908%	11.2627%	\$4,282,557	\$4,310,062	\$8,677,394	\$8,704,900

BPA Customer ID Number	BPA Customer Name	Customer Specific PF-02 Refund (1)	FY 2016 Scaled TOCA (2)	FY 2017 Scaled TOCA (2)	FY 2016 TOCA Refund	FY 2017 TOCA Refund	FY 2016 Total Refund	FY 2017 Total Refund
10360	Southside Elec Lines	\$ -	0.0979%	0.0974%	\$37,470	\$37,269	\$37,470	\$37,269
10363	Springfield Utility Board	\$490,736	1.3337%	1.3292%	\$510,400	\$508,685	\$1,001,136	\$999,422
10369	Surprise Valley Elec Coop	\$81,780	0.2364%	0.2366%	\$90,463	\$90,528	\$172,243	\$172,308
10370	Tacoma Public Utilities	\$2,979,021	5.8241%	5.7928%	\$2,228,810	\$2,216,826	\$5,207,831	\$5,195,847
10371	Tanner Elec Coop	\$59,409	0.1597%	0.1588%	\$61,109	\$60,781	\$120,519	\$120,190
10376	Tillamook PUD #1	\$287,525	0.8014%	0.7994%	\$306,702	\$305,927	\$594,227	\$593,452
10378	Coulee Dam, City of	\$ -	0.0292%	0.0291%	\$11,191	\$11,130	\$11,191	\$11,130
10379	Steilacoom, Town of	\$35,527	0.0696%	0.0692%	\$26,631	\$26,488	\$62,158	\$62,015
10388	Umatilla Elec Coop	\$557,880	1.6388%	1.6300%	\$627,134	\$623,762	\$1,185,015	\$1,181,643
10391	United Electric Coop	\$144,156	0.4339%	0.4315%	\$166,036	\$165,143	\$310,192	\$309,299
10406	U.S. DOE Albany Research Center	\$3,304	0.0066%	0.0066%	\$2,539	\$2,525	\$5,843	\$5,830
10408	U.S. Naval Station, Everett (Jim Cree	\$10,783	0.0216%	0.0215%	\$8,285	\$8,232	\$19,067	\$19,015
10409	U.S. Naval Submarine Base, Bangor	\$151,547	0.2956%	0.2940%	\$113,114	\$112,505	\$264,661	\$264,053
10426	U.S. DOE Richland Operations Office	\$193,387	0.3773%	0.3785%	\$144,373	\$144,840	\$337,760	\$338,227
10434	Vera Irrigation District	\$190,495	0.3931%	0.3909%	\$150,420	\$149,611	\$340,914	\$340,106
10436	Vigilante Elec Coop	\$ -	0.2772%	0.2757%	\$106,079	\$105,509	\$106,079	\$105,509
10440	Wahkiakum County PUD #1	\$32,517	0.0724%	0.0720%	\$27,721	\$27,572	\$60,238	\$60,089
10442	Wasco Elec Coop	\$ -	0.1848%	0.1858%	\$70,714	\$71,099	\$70,714	\$71,099
10446	Wells Rural Elec Coop	\$388,509	1.3862%	1.3787%	\$530,473	\$527,621	\$918,982	\$916,129
10448	West Oregon Elec Coop	\$48,959	0.1210%	0.1204%	\$46,313	\$46,060	\$95,273	\$95,020
10451	Whatcom County PUD #1	\$179,980	0.3799%	0.3790%	\$145,381	\$145,027	\$325,361	\$325,007
10482	Umpqua Indian Utility Cooperative	\$15,681	0.0415%	0.0415%	\$15,882	\$15,890	\$31,563	\$31,571
10502	Yakama Power	\$7,897	0.1684%	0.1675%	\$64,437	\$64,091	\$72,334	\$71,988
10597	Hermiston, City of	\$100,167	0.1827%	0.1817%	\$69,909	\$69,522	\$170,076	\$169,688
10706	Port of Seattle - SETAC In'tl. Airport	\$ -	0.2414%	0.2487%	\$92,365	\$95,190	\$92,365	\$95,190
11680	Weiser, City of	\$ -	0.0916%	0.0911%	\$35,056	\$34,868	\$35,056	\$34,868
12026	Jefferson County PUD #1	\$ -	NA	NA	\$ -	\$ -	\$ -	\$ -
Total		\$38,269,000	100.0000%	100.0000%	\$38,268,617	\$38,268,617	\$76,537,617	\$76,537,617

(1) See Exhibit B of REP Settlement Agreement, Contract No. 11PB-12322. US BIA Wapato CHWM was annexed by Yakama Power; therefore the PF-02 Refund Amount is included under Yakama Power.

(2) Adjusted TOCAs are recomputed with Grant CHWM equal to 41.75 aMW, pursuant to Section 3.4 of the Settlement Agreement. Final Scaled TOCAs reallocate headroom (when customers' net requirement is below their RHWM allocated share of the Tier 1 System) among all customers pro rata to Adjusted TOCA percentages.

This page intentionally left blank.

Appendix B

Tier 2 Load Growth Rate Customer Charge for FY 2016–2017

This page intentionally left blank.

Tier 2 Load Growth Rate Customer Charge for FY 2016–FY 2017

Section 1. Purpose

The Tier 2 Load Growth Rate Customer Charge for FY 2016 and FY 2017 is a monthly charge on a Customer’s power bill applicable to Customers that elected the Tier 2 Load Growth Rate service option. The individual customer charge is determined as an allocated share of stranded costs that BPA incurred on behalf of the Tier 2 Load Growth Rate pool.

Section 2. Customer Charge

The monthly charge for each Customer is listed in the table below and shall appear on the Customer’s power bills.

BPA Customer ID	Load Growth Customer Name	FY 2016 Monthly Customer Charge	FY 2017 Monthly Customer Charge	BPA Customer ID	Load Growth Customer Name	FY 2016 Monthly Customer Charge	FY 2017 Monthly Customer Charge
10055	Albion, City of	\$ 43	\$ 52	10246	Mason County PUD #1	\$ 1,737	\$ 1,682
10005	Alder Mutual	\$ -	\$ -	10256	Midstate Elec Coop	\$ -	\$ -
10015	Asotin County PUD #1	\$ 124	\$ 137	10080	Milton, City of	\$ 2,778	\$ 2,736
10059	Bandon, City of	\$ -	\$ 137	10082	Minidoka, City of	\$ -	\$ -
10025	Benton REA	\$ -	\$ -	10260	Modern Elec Coop	\$ -	\$ -
10061	Blaine, City of	\$ 3,976	\$ 4,097	10083	Monmouth, City of	\$ 97	\$ 298
10065	Cascade Locks, City of	\$ -	\$ -	10273	Nespelem Valley Elec Coop	\$ -	\$ -
10068	Chewelah, City of	\$ -	\$ -	10284	Ohop Mutual Light Company	\$ -	\$ -
10109	Columbia Basin Elec Coop	\$ 3,312	\$ 3,100	10288	Orcas P & L	\$ 523	\$ 766
10111	Columbia Power Coop	\$ -	\$ -	10291	Oregon Trail Coop	\$ -	\$ 2,259
10116	Consolidated Irrigation District #19	\$ -	\$ -	10304	Parkland L & W	\$ -	\$ 43
10378	Coulee Dam, Town of	\$ 254	\$ 397	10086	Plummer, City of	\$ 291	\$ 458
10070	Declo, City of	\$ 102	\$ 90	10338	Riverside Elec Coop	\$ 825	\$ 903
10071	Drain, City of	\$ 232	\$ 222	10342	Salem Elec Coop	\$ -	\$ -
10142	East End Mutual Electric	\$ 2,125	\$ 2,108	10352	Skamania County PUD #1	\$ -	\$ -
10144	Eatonville, Town of	\$ -	\$ 14	10360	South Side Electric Co.	\$ 3,059	\$ 3,128
10156	Elmhurst Mutual P & L	\$ -	\$ 827	10379	Steilacoom, Town of	\$ 728	\$ 799
10172	Fairchild, U.S. Airforce Base	\$ -	\$ -	10095	Sumas, City of	\$ 421	\$ 473
10174	Farmers Elec Coop	\$ 70	\$ 76	10097	Troy, City of	\$ 820	\$ 860
10177	Ferry County PUD #1	\$ 4,256	\$ 4,343	10406	U.S. DOE Albany Research Center	\$ 399	\$ 354
10190	Grant County PUD #2	\$ 2,185	\$ 2,240	10326	U.S. Naval Base, Bremerton	\$ -	\$ -
10197	Harney Elec Coop	\$ 3,005	\$ 2,987	10408	U.S. Naval Station, Everett (Jim Creek)	\$ -	\$ -
10597	Hermiston, City of	\$ -	\$ -	10409	U.S. Naval Submarine Base, Bangor	\$ 194	\$ 241
10202	Hood River Elec Coop	\$ 3,846	\$ 4,192	10482	Umpqua Indian Utility Cooperative	\$ -	\$ -
10230	Kittitas County PUD #1	\$ 4,682	\$ 4,527	10440	Wahkiakum County PUD #1	\$ 647	\$ 572
10235	Lakeview L & P (WA)	\$ -	\$ -	10442	Wasco Elec Coop	\$ -	\$ -
10242	Lost River Elec Coop	\$ 156	\$ 553	11680	Weiser, City of	\$ 2,152	\$ 2,278

This page intentionally left blank.

Appendix C
Slice Billing Adjustment

This page intentionally left blank.

Slice Billing Adjustment

Section 1. Purpose

The Slice Billing Adjustment is a charge on a Customer's power bill applicable to Customers that purchased the Slice Product during FY 2012–FY 2015. The individual Customer billing adjustment is an allocated share of costs resulting from the treatment of the WNP-3 settlement with Portland General Electric in the calculation of BP-12 and BP-14 PF rates.

Section 2. Billing Adjustment

The Slice Billing Adjustment for each Customer is listed in the table below. The billing adjustment shall appear on the Customer's November 2015 power bill.

Cust ID	Customer Name	November Bill Adjustment
10024	BENTON PUD	\$ 198,817
10103	CLARK PUD	\$ 317,162
10105	CLATSKANIE PUD	\$ 105,423
10123	COWLITZ	\$ 579,685
10157	EMERALD	\$ 53,749
10170	EWEB	\$ 260,651
10183	FRANKLIN PUD	\$ 113,216
10191	GRAY S HARBOR PUD	\$ 140,730
10204	IDAHO FALLS	\$ 79,781
10231	KLICKITAT PUD	\$ 34,319
10237	LEWIS PUD	\$ 139,599
10286	OKANOGAN PUD	\$ 52,466
10294	PACIFIC PUD	\$ 40,928
10306	PEND OREILLE PUD	\$ 13,584
10349	SEATTLE	\$ 526,331
10354	SNOHOMISH PUD	\$ 790,137
10370	TACOMA	\$ 430,375

This page intentionally left blank.

BP-16 Rate Proceeding

ADMINISTRATOR'S FINAL RECORD OF DECISION

Appendix C: Transmission, Ancillary and Control Area Service Rate Schedules

BP-16-A-02-AP03

July 2015



BONNEVILLE POWER ADMINISTRATION

**TRANSMISSION, ANCILLARY AND
CONTROL AREA SERVICE RATE SCHEDULES**

TABLE OF CONTENTS

	Page
COMMONLY USED ACRONYMNS AND SHORT FORMS.....	v
RATE SCHEDULES	1
FPT-16.1 Formula Power Transmission Rate.....	3
FPT-16.3 Formula Power Transmission Rate.....	5
IR-16 Integration of Resources Rate.....	9
NT-16 Network Integration Rate	13
PTP-16 Point-To-Point Rate.....	17
IS-16 Southern Intertie Rate.....	21
IM-16 Montana Intertie Rate	25
UFT-16 Use-of-Facilities Transmission Rate.....	29
AF-16 Advance Funding Rate	31
TGT-16 Townsend-Garrison Transmission Rate.....	33
PW-16 WECC and Peak Service Rate.....	35
OS-16 Oversupply Rate	37
IE-16 Eastern Intertie Rate.....	39
ACS-16 Ancillary and Control Area Services Rates	41
 GENERAL RATE SCHEDULE PROVISIONS	 67
Section I. Generally Applicable Provisions	69
A. Approval Of Rates	71
B. General Provisions	71
C. Notices	71
D. Billing and Payment.....	71
Section II. Adjustments, Charges, and Special Rate Provisions	73
A. Delivery Charge	75
B. Failure To Comply Penalty Charge.....	75

C.	Rate Adjustment Due To FERC Order Under FPA § 212	77
D.	Reservation Fee	77
E.	Transmission and Ancillary Services Rate Discounts	78
F.	Unauthorized Increase Charge (UIC).....	78
G.	CRAC, DDC, and NFB Mechanisms	80
H.	Intentional Deviation Penalty Charge	82
I.	Modified Tier 1 Cost Allocators (TOCA) for Oversupply Rate	85
Section III.	Definitions.....	89
1.	Ancillary Services	91
2.	Balancing Authority Area	91
3.	Billing Factor	91
4.	Control Area.....	91
5.	Control Area Services	92
6.	Daily Service.....	92
7.	Direct Assignment Facilities	92
8.	Direct Service Industry (DSI) Delivery.....	92
9.	Dispatchable Energy Resource	92
10.	Dispatchable Energy Resource Balancing Service	93
11.	Dynamic Schedule	93
12.	Dynamic Transfer.....	93
13.	Eastern Intertie	93
14.	Energy Imbalance Service.....	93
15.	Federal Columbia River Transmission System.....	93
16.	Federal System	93
17.	Generation Imbalance	94
18.	Generation Imbalance Service	94
19.	Heavy Load Hours (HLH).....	94
20.	Hourly Non-Firm Service	94
21.	Integrated Demand.....	94
22.	Light Load Hours (LLH).....	94

23.	Long-Term Firm Point-To-Point (PTP) Transmission Service	95
24.	Main Grid.....	95
25.	Main Grid Distance.....	95
26.	Main Grid Interconnection Terminal	95
27.	Main Grid Miscellaneous Facilities	95
28.	Main Grid Terminal	95
29.	Measured Demand	96
30.	Metered Demand.....	96
31.	Montana Intertie.....	96
32.	Monthly Service	96
33.	Monthly Transmission Peak Load	97
34.	Network (or Integrated Network).....	97
35.	Network Integration Transmission (NT) Service.....	97
36.	Network Load	97
37.	Network Upgrades	97
38.	Non-Firm Point-To-Point (PTP) Transmission Service	97
39.	Operating Reserve – Spinning Reserve Service.....	98
40.	Operating Reserve – Supplemental Reserve Service	98
41.	Operating Reserve Requirement	98
42.	Persistent Deviation	98
43.	Point of Delivery (POD)	99
44.	Point of Integration (POI)	100
45.	Point of Interconnection (POI).....	100
46.	Point of Receipt (POR)	100
47.	Ratchet Demand.....	100
48.	Reactive Power	100
49.	Reactive Supply and Voltage Control from Generation Sources Service.....	100
50.	Regulation and Frequency Response Service	101
51.	Reliability Obligations	101
52.	Reserved Capacity.....	101

53.	Scheduled Demand	102
54.	Scheduling, System Control, and Dispatch Service.....	102
55.	Secondary System	102
56.	Secondary System Distance	102
57.	Secondary System Interconnection Terminal.....	102
58.	Secondary System Intermediate Terminal	102
59.	Secondary Transformation	102
60.	Short-Term Firm Point-To-Point (PTP) Transmission Service	103
61.	Southern Intertie.....	103
62.	Spill Condition	103
63.	Spinning Reserve Requirement.....	103
64.	Station Control Error.....	103
65.	Super Forecast Methodology	104
66.	Supplemental Reserve Requirement	104
67.	Total Transmission Demand	104
68.	Transmission Customer	104
69.	Transmission Demand	104
70.	Transmission Provider	104
71.	Utility Delivery	105
72.	Variable Energy Resource.....	105
73.	Variable Energy Resource Balancing Service.....	105
74.	Weekly Service	105

COMMONLY USED ACRONYMS AND SHORT FORMS

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

FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
<i>inc</i>	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
IRMP	Irrigation Rate Mitigation Product
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation

NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMP	Oversupply Management Protocol
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability
PF	Priority Firm Power
PFIA	Projects Funded in Advance
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
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)

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

TRANSMISSION RATE SCHEDULES

This page intentionally left blank

FPT-16.1

FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-14.1 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated each quarter according to the following formula:

$$\left(1 + \frac{\text{GSR}_q}{\$1.634/\text{kW}/\text{mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES

1. Main Grid Distance	\$0.0700 per mile
2. Main Grid Interconnection Terminal	\$0.73/kW
3. Main Grid Terminal	\$0.81/kW
4. Main Grid Miscellaneous Facilities	\$3.99/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.6884 per mile
2. Secondary System Transformation	\$7.53/kW
3. Secondary System Intermediate Terminal	\$2.91/kW
4. Secondary System Interconnection Terminal	\$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

FPT-16.3

FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-14.3 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. FY 2016 Rates

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated each quarter according to the following formula:

$$\left(1 + \frac{\text{GSR}_q}{\$1.666/\text{kW}/\text{mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	\$0.0679 per mile
2.	Main Grid Interconnection Terminal	\$0.71/kW
3.	Main Grid Terminal	\$0.79/kW
4.	Main Grid Miscellaneous Facilities	\$3.87/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.6676 per mile
2.	Secondary System Transformation	\$7.30/kW
3.	Secondary System Intermediate Terminal	\$2.82/kW
4.	Secondary System Interconnection Terminal	\$2.00/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

B. FY 2017 Rates

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.634/kW/mo} \right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	\$0.0700 per mile
2.	Main Grid Interconnection Terminal	\$0.73/kW
3.	Main Grid Terminal	\$0.81/kW
4.	Main Grid Miscellaneous Facilities	\$3.99/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.6884 per mile
2.	Secondary System Transformation	\$7.53/kW
3.	Secondary System Intermediate Terminal	\$2.91/kW
4.	Secondary System Interconnection Terminal	\$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking transmission service under FPT agreements are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

This page intentionally left blank.

IR-16 INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes the IR-14 rate schedule and is available for transmission of non-Federal power for full-year firm transmission service and non-firm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The IR rates in sections A and B, below, are calculated each quarter. These rates shall be calculated to three decimal places. The monthly IR rate shall be as provided in section A or section B.

A. RATE

The rate shall be the sum of:

1. \$1.790 per kilowatt per month (\$/kW/mo); and
2. ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo.

B. SHORT DISTANCE DISCOUNT (SDD) RATE

For Points of Integration (POI) specified in the IR agreement as being short-distance POIs, for which Network facilities are used for a distance of less than 75 circuit miles, the monthly rate shall be the sum of:

1. \$0.301/kW/mo; and
2. ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo; and

3. $(0.6 + (0.4 * \text{transmission distance}/75)) * \$1.489/\text{kW}/\text{mo}$

Where:

The transmission distance is the circuit miles between a designated POI for a generating resource of the customer and a designated Point of Delivery serving load of the customer. Short-distance POIs are determined by BPA after considering factors in addition to transmission distance.

SECTION III. BILLING FACTORS

The Billing Factor for rates specified in section II shall be the largest of:

- A. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

To the extent that the agreement provides for the IR customer to be billed for transmission service in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at an hourly non-firm rate, such excess transmission service shall not contribute to the Billing Factor for the IR rates in section II, provided that the IR customer requests such treatment and BPA approves such request in accordance with the prescribed provisions in the agreement. The rate for transmission service in excess of the Transmission Demand will be pursuant to the Point-to-Point Rate (PTP-16) for Hourly Non-Firm Service.

When the Scheduled Demand or Ratchet Demand is the Billing Factor, short-distance POIs shall be charged the Rate specified in section II.A. for the amount in excess of Transmission Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support IR transmission service are available under the ACS rate schedule. IR customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in IR service.

B. DELIVERY CHARGE

Customers taking service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA may waive or reduce the Ratchet Demand. An IR customer seeking a reduction or waiver must demonstrate good cause for relief, including a demonstration that:

1. The event that resulted in the Ratchet Demand:
 - a. was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and
 - b. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; or
2. The event that resulted in the Ratchet Demand:
 - a. was inadvertent;
 - b. could not have been avoided by the exercise of reasonable care;
 - c. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; and
 - d. was not part of a recurring pattern of conduct by the IR customer.

If the IR customer causes a Ratchet Demand to be established in a series of months during which the IR customer has not received notice from BPA of such Ratchet Demands by billing or otherwise, and the Ratchet Demand(s) established after the first Ratchet Demand were due to the lack of notice, then BPA may establish a Ratchet Demand for the IR customer based on the highest Ratchet Demand in the series. This highest Ratchet Demand will be charged in the month it is established and the following 11 months. All other Ratchet Demands based on such a series (including the Ratchet Demand established in the first month if it is not the highest Ratchet Demand) will be waived.

Ratchet Demand Relief is not available in the month in which the Ratchet Demand was established. For that month, the Customer will be assessed charges based upon the highest hourly Scheduled Demand Billing Factor.

E. SELF-SUPPLY OF REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

A credit for self-supply of Reactive Supply and Voltage Control from Generation Sources Service will be available for IR customers on a basis equivalent to the credit for PTP Transmission Customers.

NT-16 NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-14 rate schedule. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities, including Conditional Firm (CF) Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

\$1.735 per kilowatt per month

SECTION III. BILLING FACTOR

- A. The monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission System Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking NT Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. SHORT-DISTANCE DISCOUNT (SDD)

A Customer's monthly NT bill shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that (1) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (2) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load. A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

The NT monthly bill will be reduced by a credit equal to:

$$\text{Avg. Generation of the DNR SD during HLH} * \text{NT Rate} * \frac{75 - \text{Tx Distance}}{75} * 0.4$$

Where:

Average
Generation

during HLH = The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's Point(s) of Delivery (POD) to the total DNR SD designated capacity.

The output serving Network Load is:

1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load.
2. in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = \$1.735 per kilowatt per month

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD Point of Receipt (POR) and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD.

1. BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's designated capacity is fully allocated to the qualifying PODs, subject to section 2 below. The Tx Distance shall be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD.
2. The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load.
3. For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Tx Distance shall be zero.

Qualifying Capacity = The sum of all DNR SD designated capacity allocated to the Customer's POD(s).
For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity shall be the total DNR SD designated capacity.

Behind the Meter Resource = A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

E. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Customer under an applicable rate schedule.

F. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

G. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

PTP-16 POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-14 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, including Conditional Firm (CF) Transmission Service, and for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements. Terms and conditions of PTP are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.489 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 \$0.068 per kilowatt per day

b. Day 6 and beyond \$0.049 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.28 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM AND NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or
2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking PTP Transmission Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

E. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of the Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

F. SHORT-DISTANCE DISCOUNT (SDD)

When a Point of Receipt and Point of Delivery use FCRTS facilities for a distance of less than 75 circuit miles and are designated as being short distance in the PTP Service Agreement, the monthly capacity reservations for the relevant POR and POD shall be adjusted, for the purpose of computing the monthly bill for annual service, by the following factor:

$$0.6 + (0.4 * \text{transmission distance} / 75)$$

Such adjusted monthly POR and POD reservations shall be used to compute the billing factors in section III.A. to calculate the monthly bill for Long-Term Firm PTP Transmission Service. The POD capacity reservation eligible for the SDD may be no larger than the POR capacity reservation. System sales do not qualify for SDD. The distance used to calculate the SDD will be contractually specified and based upon path(s) identified in power flow studies. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD shall be between the POR and the POD farthest from the POR.

If the customer requests secondary PORs or PODs that use SDD-adjusted capacity reservations for any period of time during a month, the SDD shall not be applied that month.

G. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

H. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the PTP Transmission Customer under an applicable rate schedule.

I. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

J. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

IS-16
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-14 rate schedule. It is available to Transmission Customers taking Point-to-Point Transmission (PTP) Service over the Federal Columbia River Transmission System (FCRTS) Southern Intertie facilities. Terms and conditions of service are specified in the Open Access Transmission Tariff or, for customers that executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.230 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 \$0.057 per kilowatt per day

b. Day 6 and beyond \$0.040 per kilowatt per day

2. Hourly Firm and Non-Firm Service

3.53 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or
2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Factor shall be as specified in the agreement.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Southern Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

IM-16
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-14 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$0.598 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service

a. Days 1 through 5 \$0.028 per kilowatt per day

b. Day 6 and beyond \$0.020 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.72 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE NON-FIRM SERVICE

The Billing Factor for each rate specified in section II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or
2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule for the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

This page intentionally left blank

UFT-16

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-14 rate schedule unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

- A. From time to time, but not more often than once a year, BPA shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA and that are used to transmit electric power:
1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA and such other entity.
 2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.
- B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used, divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission Demand/capacity reservation for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

- A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

For facilities used by more than one customer, BPA may charge a monthly amount equal to the annual cost of such facilities prorated based on relative use of the facilities, divided by 12.

SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor shall be the largest of:

- A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;
- B. The highest hourly Measured or Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that are required to support UFT transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

AF-16 ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-14 rate schedule and is available to customers that execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

- A. Interconnection or integration of resources and loads to the FCRTS;
- B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or
- C. Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

The charge is:

- A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or
- B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in the agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA shall be specified in the agreement as one of the following options:

- 1. A lump sum advance payment;
- 2. Advance payments pursuant to a schedule of progress payments; or

3. Other payment arrangement, as determined by BPA.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

For charges under section II.A., BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-16

TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-14 rate schedule and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Columbia River Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be a surplus or a deficit. Such surplus or deficit for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from non-firm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower the unit rate will be.

If BPA provides firm transmission service in its section of the Montana (Eastern) Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by BPA for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer.

A. NON-FIRM TRANSMISSION CHARGE

This charge will be filed as a separate rate schedule, the Eastern intertie (IE) rate.

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE

$$\text{Intertie Charge} = [((\text{TAC} / 12) - \text{NFR}) * \frac{(\text{CR} - \text{EC})}{\text{TCR}}]$$

SECTION III. DEFINITIONS

- A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500 kV Transmission line including terminals, and prior to extension of the 500 kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer

at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

- B. NFR = Non-firm Revenues, which are equal to (1) the product of the Non-firm Transmission Charge described in II.A. above and the total non-firm energy transmitted over the Townsend-Garrison line segment under such charge during such month; plus (2) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.
- C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500 kV transmission facilities as specified in its firm transmission agreement.
- D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.
- E. EC = Exchange Credit for each customer, which is the product of (1) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and (2) the capacity BPA obtains in the Townsend-Broadview 500 kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

PW-16
WECC AND PEAK SERVICE RATE

SECTION I. AVAILABILITY

The rate below applies to all loads in the BPA Control Area except for loads of customers billed directly by WECC or by Peak Reliability. The WECC and Peak Service rate recovers the costs billed to BPA by WECC and Peak Reliability based on loads in the BPA Control Area. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. WECC RATE

0.05 mills per kilowatthour

B. PEAK RATE

0.05 mills per kilowatthour

SECTION III. BILLING FACTORS

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

This page intentionally left blank.

OS-16 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-14 rate schedule. The Oversupply Rate applies to generators in the BPA Balancing Authority Area that are specified as the source on transmission schedules for the hours that BPA displaces generation pursuant to the Open Access Transmission Tariff (OATT), Attachment P (Oversupply Event Hours), and to customers that purchase power under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate, for the charges to BPA Power Services under section II.C.

The Oversupply Charge shall collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2015, through September 30, 2017. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2016-2017 rate period are billed and fully paid. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

A. OVERSUPPLY RATE

For each month, the Oversupply rate in dollars per megawatthour (\$/MWh) shall be:

$$\frac{\textit{Displacement Cost}}{\sum \textit{Scheduled Generation}}$$

Where:

Displacement Cost = the amount BPA paid pursuant to OATT Attachment P to displace output from generating facilities for the calendar month, in dollars.

Scheduled Generation = For each generator in the BPA Balancing Authority Area, the sum of transmission schedules (e-Tags) during Oversupply Event Hours that specify such generator as the source, in megawatthours.

The after-the-fact schedule shall be used for power dynamically transferred out of BPA's Balancing Authority Area.

\sum *Scheduled Generation* = the sum of all Scheduled Generation, in megawatthours.

B. OVERSUPPLY BILLING FACTORS

The billing factor for the monthly Oversupply Rate is the sum of the customer's Scheduled Generation during the month.

C. OVERSUPPLY CHARGES TO BPA POWER SERVICES

Charges to BPA Power Services for its applicable Scheduled Generation under this rate schedule shall be billed to customers purchasing under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate schedules using a Modified TOCA. The charge for each such customer shall be the Oversupply Charge amount charged to BPA Power Services multiplied by each customer's Modified Tier 1 Cost Allocator (TOCA). The Modified TOCA for each customer for each fiscal year is specified in GRSP II.I.

SECTION III. BILLING

A. OVERSUPPLY CHARGE

The Oversupply charge shall be included on bills for the month after Displacement Costs are incurred, subject to the billing cap; *i.e.*, there will be a one-month lag between Scheduled Generation and billing the Oversupply charge. Any Displacement Cost not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Cost for the month, shall be included on the following month's bill, subject to the billing cap, and on subsequent bills as necessary until all Displacement Costs have been billed.

B. BILLING CAP

Total billing to all customers for the Oversupply Charges may not exceed \$8 million in any one month. If the total Oversupply Charges exceed \$8 million in any month, the excess over \$8 million shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall be billed in each subsequent month, subject to this billing cap, until all charges are billed.

C. BILLING FOR OVERSUPPLY CHARGES TO BPA POWER SERVICES

The charge for BPA Power Services costs (section II.C) shall be separately included on each applicable customer's transmission bill.

IE-16
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-14 rate schedule and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) for non-firm transmission service on the portion of Eastern Intertie capacity that exceeds BPA's firm transmission rights. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The rate shall not exceed 1.48 mills per kilowatthour.

SECTION III. BILLING FACTOR

The Billing Factor shall be the scheduled kilowatthours, unless otherwise specified in the Montana Intertie Agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that may be required to support IE transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

This page intentionally left blank

ACS-16

ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-14 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control, and Dispatch Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. NT Service

The rate shall not exceed \$0.350 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service and IR Service

The rate shall not exceed \$0.301 per kilowatt per month.

c. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 \$0.014 per kilowatt per day

(b) Day 6 and beyond \$0.010 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.87 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in sections 1.b. and 1.c.(1) and for the Hourly Firm PTP Transmission Service rate specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control, and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

- (1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - (a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - (b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
- (2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-16).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to section II.F.2.a. of the GRSPs.

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, the

Southern Intertie, and the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

The rates for GSR Service will be set on a quarterly basis, beginning October 2015, according to the formulas below. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month (\$/kW/mo), shall not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

bd = 513,961 MW-mo = Average of forecasted FY 2016 and FY 2017 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-Federal GSR cost (\$) to be paid by BPA under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter.

U_{q-1} = Payments of non-Federal GSR cost (\$) made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA would reduce this cost. U_{q-1} is a true-up for any deviation of non-Federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2015, U_{q-1} is zero.

S_q = Reduction in effective billing demand (MW-mo) for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter.

Z_{q-1} = True-up (\$) for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective

October 1, 2015, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation.

“Relevant quarter” refers to the 3-month period for which the rate is being determined.

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates shall not exceed:

(a) Days 1 through 5 (\$/kW/day)

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 5 \text{ days}}$$

(b) Day 6 and beyond (\$/kW/day)

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 7 \text{ days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate shall not exceed:

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 5 \text{ days} * 16 \text{ hours}}$$

Where:

The “Long-Term Service Rate” specified in the formulas in sections 1.b.(1)(a) and (b) and section 1.b.(2), above, is the rate determined in section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in \$/kW/mo.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in

sections 1.b. and 1.c.(1) and for Hourly Firm PTP Transmission Service specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

- (1) the sum of the capacity reservations at the Point(s) of Receipt, or
- (2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

- (1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - (a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - (b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
- (2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-16).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to section II.F.2.a. of the GRSPs.

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

- (2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

- (1) No credit is given when energy taken is less than the scheduled energy.
- (2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-16 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA, the rate shall not exceed 11.40 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11 mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer’s Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 10.45 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their

self-supply or third-party supply obligations, the rate shall be 12.02 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

- (1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.
- (2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

- (1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section 1 of this ACS-16 Generation Imbalance Service rate schedule.

For Variable Energy Resources (wind and solar resources), BPA will remove specific scheduled periods for billing purposes from a Persistent Deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

d. No Credit for Negative Deviations During Curtailments

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the ACS-16 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and (3).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

- (1) wind resources
- (2) solar resources

- (3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 11.40 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 10.45 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.02 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c. of this rate schedule.

Variable Energy Resource Balancing Service (“VERBS” or “Balancing Service”) is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator’s schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

2. BALANCING SERVICE FOR WIND RESOURCES

The total charge for Balancing Service is the applicable rate in section 2.a., below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. BALANCING SERVICE RATES

(1) Rate for 30/60 Committed Scheduling

This rate is applicable to customers taking Balancing Service that commit to receive BPA’s 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.80 per kilowatt per month

(2) Rate for 40/15 Committed Scheduling

This rate is applicable to customers taking Balancing Service that commit to receive BPA’s 40-minute signal for each 15-minute schedule period (40/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.54 per kilowatt per month

(3) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing Service that commit to receive BPA’s 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$0.33 per kilowatt per month

(4) Rate for Uncommitted Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/60, 40/15 or 30/15 scheduling (“uncommitted scheduling”).

- (a) Regulating Reserves \$0.08 per kilowatt per month
- (b) Following Reserves \$0.32 per kilowatt per month
- (c) Imbalance Reserves \$1.08 per kilowatt per month
- (d) Opt Out Fee

The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.H) shall be \$0.20 per kilowatt per month.

b. BILLING FACTOR

The Billing Factor for rates in section 2.a. is as follows:

- (1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.
- (2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.
- (3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior

to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

- (1) The rates under section 2.a. above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA’s Balancing Authority Area to another Balancing Authority Area.
- (2) Individual rate components under section 2.a.(1)-(5) above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

3. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

- (1) Regulating Reserves \$0.04 per kilowatt per month
- (2) Following Reserves \$0.17 per kilowatt per month

b. BILLING FACTOR

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

c. EXCEPTIONS

See section 2.c. above.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

- a. the customer elected to self-supply in accordance with section 2.c. but is unable to self-supply one or more components to Variable Energy Resource Balancing Service; or
- b. the customer has a projected generator interconnection date after FY 2017, but chooses to interconnect during the FY 2016–2017 rate period; or
- c. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or
- d. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3) above, but chooses to take a Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or
- e. the customer either elected to dynamically transfer its resource out of BPA’s Balancing Authority Area or has successfully dynamically transferred its resource out of BPA’s Balancing Authority Area, but chooses to keep its resource in BPA’s Balancing Authority Area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section 3 below. Dispatchable Energy Resource Balancing Service (“DERBS”) is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge determined by applying the rates in section 1 below, plus Direct Assignment Charges in section 4 below.

1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

- a. Incremental Reserves = 18.15 mills per kW maximum hourly deviation
- b. Decremental Reserves = 3.94 mills per kW maximum hourly deviation

2. BILLING FACTORS

- a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative Station Control Error (under-generation), including ramp periods, that exceeds 3 MW for that hour.
- b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive Station Control Error (over-generation), including ramp periods, that exceeds 3 MW for that hour.

3. EXCEPTIONS

- a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA’s Balancing Authority Area to another Balancing Authority Area.
- b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.
- c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA’s

Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

- d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

- a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or
- b. a customer has a projected generator interconnection date after FY 2017 but chooses to interconnect during the FY 2016-2017 rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2016-2017 rate period; or
- d. the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.C.

B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in GRSP II.G.

GENERAL RATE SCHEDULE PROVISIONS

This page intentionally left blank.

SECTION I. GENERALLY APPLICABLE PROVISIONS

This page intentionally left blank

A. APPROVAL OF RATES

These BP-16 rate schedules and General Rate Schedule Provisions (GRSPs) for Transmission and Ancillary Service Rates shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC or Commission). Bonneville Power Administration (BPA) has requested that FERC make these rates and GRSPs effective on October 1, 2015. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. GENERAL PROVISIONS

These BP-16 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-14 rate schedules (which became effective October 1, 2013) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C. § 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C. § 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C. § 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C. § 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C. § 824(i)-(l).

These BP-16 rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. NOTICES

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

D. BILLING AND PAYMENT

1. BILLING PROCEDURE

Within a reasonable time after the first day of each month, BPA shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff and other agreements during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BPA, or by wire transfer to a bank named by BPA.

2. INTEREST ON UNPAID BALANCES

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BPA.

3. CUSTOMER DEFAULT

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BPA on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BPA notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BPA may notify the Transmission Customer that it plans to terminate services in sixty (60) days. The Transmission Customer may use the dispute resolution procedures to contest such termination. In the event of a billing dispute between BPA and the Transmission Customer, BPA will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BPA may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

**SECTION II. ADJUSTMENTS, CHARGES, AND
SPECIAL RATE PROVISIONS**

This page intentionally left blank

A. DELIVERY CHARGE

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery and Utility Delivery facilities and equipment.

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-16) Rate, section III

b. Utility Delivery

\$1.285 per kilowatt per month

2. BILLING FACTOR

a. Utility Delivery

The monthly Billing Factor for the Utility Delivery rate in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as providing Utility Delivery service.

The monthly Utility Delivery Billing Factor shall be adjusted for customers that pay for Utility Delivery service under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities and equipment used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

B. FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with BPA’s dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. Parties that are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a *force majeure* on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify BPA of the situation upon occurrence of the *force majeure*.

1. RATES

The Failure to Comply Penalty Charge shall be the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest.

If no adequate hourly index exists, an alternative index will be used. At least 30 days prior to the use of such index BPA will post on its OASIS Web site the name of the index to be used. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

2. BILLING FACTOR

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten (10) minutes after issuance of the order in any of the following situations:

- a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.
- b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.
- c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by BPA in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

In addition to the Failure to Comply Penalty Charge, the party will be assessed the costs of alternate measures taken by BPA in order to manage the reliability of the FCRTS due to the failure to comply.

The party will also be assessed monetary penalties imposed on BPA by a regional reliability organization, electric reliability organization, or FERC for a violation of a reliability standard authorized under section 215 of the Energy Policy Act of 2005, if the violation was caused by the party's failure to comply.

C. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

If, after review by FERC, the NT, PTP, ACS, IS, or IM rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to the rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective only prospectively from the date of the final FERC order granting final approval of the rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under the rate schedule prior to the effective date of such prospective modification.

D. RESERVATION FEE

The Reservation Fee is a nonrefundable fee that shall be charged to any PTP Transmission Service customer that postpones the commencement of service by requesting an extension of the Service Commencement Date specified in the executed Service Agreement.

The Reservation Fee shall be specified in the executed agreement for transmission service.

1. FEE

The Reservation Fee shall be a nonrefundable fee equal to one month's charge for the requested Long-Term Firm Point-to-Point Transmission Service for each year or fraction of a year for which the customer chooses to extend the Service Commencement Date. The Reservation Fee shall be paid annually until transmission service begins or the reservation period ends, whichever occurs first.

2. PAYMENT

The Reservation Fee for the first extension of the Service Commencement Date shall be paid in a lump sum within 30 days of the original Service Commencement Date. For subsequent extensions, the Reservation Fee shall be paid in a lump sum within 30 days of the anniversary date of the original Service Commencement Date.

E. TRANSMISSION AND ANCILLARY SERVICES RATE DISCOUNTS

BPA may offer discounted rates for transmission and ancillary services available under the Open Access Transmission Tariff and to the extent provided for in the PTP, IS, IM, and ACS rate schedules.

Three principal requirements apply to discounts for transmission service and Ancillary Services provided by BPA in conjunction with its provision of transmission service, as follows:

1. any offer of a discount made by BPA must be announced to all Eligible Customers solely by posting on the OASIS;
2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and
3. once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for transmission service on a path, from point(s) of receipt to point(s) of delivery, BPA must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that connect to the same point(s) of delivery on the transmission system.

A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BPA's transmission system.

F. UNAUTHORIZED INCREASE CHARGE (UIC)

Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM rate schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). BPA will notify a Transmission Customer that is subject to a UIC once BPA has verified the UIC amount.

1. RATES

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

The UIC rate shall be the lesser of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the

WECC, or (ii) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way dynamic schedules, BPA shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA will sum these amounts that exceed capacity reservations for all PODs and for all PORs. The Billing Factor for the monthly billing period shall be the greater of the total of the POD hourly amounts or the total of the POR hourly amounts.

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A Transmission Customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UIC:

- (1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;
- (2) could not have been avoided by the exercise of reasonable care; and
- (3) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA OASIS Web site.

b. Transmission Rate if BPA Waives or Reduces the UIC

If BPA waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates shall apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS, or IM rate schedules if BPA waives or reduces the UIC:

- (1) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for one day of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.
- (2) If BPA waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.
- (3) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

For a Transmission Customer taking Point-to-Point Transmission Service under the PTP, IS, or IM rate schedules, the Billing Factor for rates in this section 3.b. shall be: (a) the Transmission Customer's highest excess transmission demand for which BPA waives the UIC; or (b) if BPA reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

G. CRAC, DDC, AND NFB MECHANISMS

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.C, II.E, and II.N.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the

amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service
- Variable Energy Resource Balancing Service (VERBS)

Exception: For the VERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.E.2.a.(4), opt out fee, section III.E.4., Direct Assignment Charges and Intentional Deviation, GRSP II.H.

- Dispatchable Energy Resource Balancing Service (DERBS)

Exception: For the DERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.F.4., Direct Assignment Charges.

1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

2. CUSTOMER CREDIT FOR THE ACS DDC

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed from the ACS rates specified above; the balance of the DDC Amount is to be distributed from specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times

each of the applicable rates times the billing factors for each rate for each customer.

3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

The CRAC, DDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.C, II.E, and II.N, are incorporated by reference.

H. INTENTIONAL DEVIATION PENALTY CHARGE

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-16 Variable Energy Resources Balancing Service rate.

Exceptions:

- a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS-16 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for

Generation penalty charge as specified in the ACS-16 Generation Imbalance Service rate schedule (section III.B.2.c).

- b. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.
- c. Customers participating in the Customer Supplied Generation Imbalance (“CSGI”) Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be \$100 per megawatt-hour (MWh).

An Intentional Deviation event occurs when:

$$\text{ABS}(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) > 1$$

(See section 3, below, for definition of terms.)

3. BILLING FACTOR

The Billing Factor in MWh shall be:

$$\text{ABS}(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) - 1$$

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following three values:

- 1) for wind generating customers taking VERBS at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3)), the applicable committed schedule value provided by BPA;
- 2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40-minute forecast schedule value produced by the Super Forecast Methodology; or

- 3) for solar generating customers taking VERBS (section 3), the matrix forecast schedule value or applicable committed schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

$$\text{ABS(Station Control Error)} \leq \text{ABS(Intentional Deviation Measurement Value Error)} + 1 \text{ MW}$$

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

I. MODIFIED TIER 1 COST ALLOCATORS (TOCA) FOR OVERSUPPLY RATE

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10005	Alder Mutual	0.0000775	0.0000777
10015	Asotin County PUD #1	0.0000818	0.0000814
10024	Benton County PUD #1	0.0287656	0.0286115
10025	Benton REA	0.0095225	0.0094715
10027	Big Bend Elec Coop	0.0087323	0.0086855
10029	Blachly Lane Elec Coop	0.0025137	0.0025002
10044	Canby, City of	0.0028981	0.0028826
10046	Central Electric Coop	0.0116799	0.0116173
10047	Central Lincoln PUD	0.0220629	0.0220015
10055	Albion, City of	0.0000568	0.0000565
10057	Ashland, City of	0.0030064	0.0029903
10059	Bandon, City of	0.0010887	0.0010843
10061	Blaine, City of	0.0012481	0.0012414
10062	Bonnors Ferry, City of	0.0007591	0.0007551
10064	Burley, City of	0.0019817	0.0019769
10065	Cascade Locks, City of	0.0003153	0.0003138
10066	Centralia, City of	0.0034778	0.0034592
10067	Cheney, City of	0.0022571	0.0022450
10068	Chewelah, City of	0.0003755	0.0003735
10070	Declo, City of	0.0000511	0.0000508
10071	Drain, City of	0.0002732	0.0002717
10072	Ellensburg, City of	0.0034222	0.0034039
10074	Forest Grove, City of	0.0038075	0.0037871
10076	Heyburn, City of	0.0006874	0.0006837
10078	McCleary, City of	0.0005080	0.0005066
10079	McMinnville, City of	0.0125829	0.0125154
10080	Milton, Town of	0.0010611	0.0010554
10081	Milton-Freewater, City of	0.0014324	0.0014310
10082	Minidoka, City of	0.0000164	0.0000166
10083	Monmouth, City of	0.0011935	0.0011871
10086	Plummer, City of	0.0005630	0.0005600
10087	Port Angeles, City of	0.0120226	0.0119759
10089	Richland, City of	0.0147767	0.0146975
10091	Rupert, City of	0.0013445	0.0013373
10094	Soda Springs, City of	0.0004238	0.0004194
10095	Sumas, Town of	0.0005197	0.0005170

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10097	Troy, City of	0.0002908	0.0002893
10101	Clallam County PUD #1	0.0108490	0.0107909
10103	Clark County PUD #1	0.0427033	0.0426580
10105	Clatskanie PUD	0.0132478	0.0131768
10106	Clearwater Power	0.0033347	0.0033303
10109	Columbia Basin Elec Coop	0.0017292	0.0017199
10111	Columbia Power Coop	0.0004186	0.0004191
10112	Columbia River PUD	0.0080633	0.0080784
10113	Columbia REA	0.0053787	0.0053499
10116	Consolidated Irrigation District #19	0.0000286	0.0000284
10118	Consumers Power	0.0065175	0.0064826
10121	Coos Curry Elec Coop	0.0057280	0.0057119
10123	Cowlitz County PUD #1	0.0783695	0.0779496
10136	Douglas Electric Cooperative	0.0025973	0.0025906
10142	East End Mutual Electric	0.0003835	0.0003814
10144	Eatonville, City of	0.0004780	0.0004780
10156	Elmhurst Mutual P & L	0.0045851	0.0045757
10157	Emerald PUD	0.0067304	0.0067541
10158	Energy Northwest	0.0003949	0.0003925
10170	Eugene Water & Electric Board	0.0343469	0.0342560
10172	U.S. Airforce Base, Fairchild	0.0008172	0.0008211
10173	Fall River Elec Coop	0.0047277	0.0047023
10174	Farmers Elec Coop	0.0000724	0.0000720
10177	Ferry County PUD #1	0.0016645	0.0016556
10179	Flathead Elec Coop	0.0238053	0.0236778
10183	Franklin County PUD #1	0.0167458	0.0166560
10186	Glacier Elec Coop	0.0030419	0.0030256
10190	Grant County PUD #2	0.0007408	0.0007369
10191	Grays Harbor PUD #1	0.0187243	0.0186240
10197	Harney Elec Coop	0.0032468	0.0032294
10202	Hood River Elec Coop	0.0018692	0.0018592
10203	Idaho County L & P	0.0008866	0.0008819
10204	Idaho Falls Power	0.0113525	0.0112916
10209	Inland P & L	0.0153744	0.0152920
10230	Kittitas County PUD #1	0.0013846	0.0013771
10231	Klickitat County PUD #1	0.0052311	0.0052031
10234	Kootenai Electric Coop	0.0072775	0.0072385
10235	Lakeview L & P (WA)	0.0045743	0.0045726

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10236	Lane County Elec Coop	0.0039476	0.0039280
10237	Lewis County PUD #1	0.0156264	0.0155702
10239	Lincoln Elec Coop (MT)	0.0019784	0.0019661
10242	Lost River Elec Coop	0.0013593	0.0013520
10244	Lower Valley Energy	0.0122773	0.0122116
10246	Mason County PUD #1	0.0012824	0.0012755
10247	Mason County PUD #3	0.0114057	0.0113446
10256	Midstate Elec Coop	0.0065469	0.0065413
10258	Mission Valley	0.0053227	0.0053682
10259	Missoula Elec Coop	0.0038326	0.0038301
10260	Modern Elec Coop	0.0036974	0.0037095
10273	Nespelem Valley Elec Coop	0.0008392	0.0008347
10278	Northern Lights	0.0051267	0.0050993
10279	Northern Wasco County PUD	0.0092419	0.0091924
10284	Ohop Mutual Light Company	0.0014078	0.0014084
10285	Okanogan County Elec Coop	0.0009303	0.0009266
10286	Okanogan County PUD #1	0.0065514	0.0065162
10288	Orcas P & L	0.0035296	0.0035107
10291	Oregon Trail Coop	0.0112063	0.0112385
10294	Pacific County PUD #2	0.0051838	0.0051560
10304	Parkland L & W	0.0019989	0.0019968
10306	Pend Oreille County PUD #1	0.0008002	0.0036566
10307	Peninsula Light Company	0.0102722	0.0102172
10326	U.S. Naval Base, Bremerton	0.0041294	0.0041072
10331	Raft River Elec Coop	0.0050216	0.0050338
10333	Ravalli County Elec Coop	0.0026420	0.0026279
10338	Riverside Elec Coop	0.0003385	0.0003367
10342	Salem Elec Coop	0.0053746	0.0053605
10343	Salmon River Elec Coop	0.0017627	0.0017524
10349	Seattle City Light	0.0747610	0.0743604
10352	Skamania County PUD #1	0.0022162	0.0022159
10354	Snohomish County PUD #1	0.1103304	0.1110411
10360	Southside Elec Lines	0.0009653	0.0009602
10363	Springfield Utility Board	0.0131493	0.0131054
10369	Surprise Valley Elec Coop	0.0023306	0.0023323
10370	Tacoma Public Utilities	0.0574202	0.0571126
10371	Tanner Elec Coop	0.0015743	0.0015659
10376	Tillamook PUD #1	0.0079015	0.0078817
10378	Coulee Dam, City of	0.0002883	0.0002868

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10379	Steilacoom, Town of	0.0006861	0.0006824
10388	Umatilla Elec Coop	0.0161567	0.0160701
10391	United Electric Coop	0.0042775	0.0042546
10406	U.S. DOE Albany Research Center	0.0000654	0.0000651
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002134	0.0002121
10409	U.S. Naval Submarine Base, Bangor	0.0029141	0.0028985
10426	U.S. DOE Richland Operations Office	0.0037194	0.0037315
10434	Vera Irrigation District	0.0038752	0.0038545
10436	Vigilante Elec Coop	0.0027329	0.0027182
10440	Wahkiakum County PUD #1	0.0007142	0.0007103
10442	Wasco Elec Coop	0.0018218	0.0018317
10446	Wells Rural Elec Coop	0.0136664	0.0135932
10448	West Oregon Elec Coop	0.0011932	0.0011867
10451	Whatcom County PUD #1	0.0037454	0.0037364
10482	Umpqua Indian Utility Cooperative	0.0004092	0.0004094
10502	Yakama Power	0.0016601	0.0016512
10597	Hermiston, City of	0.0018011	0.0017911
10706	Port of Seattle - SETAC In'tl. Airport	0.0023796	0.0024524
11680	Weiser, City of	0.0009031	0.0008983
12026	Jefferson County PUD #1	0.0060820	0.0061064
10007	Alcoa	0.0108078	0.0107499
10312	Port Townsend Paper	0.0023057	0.0022933
10298	PNGC Aggregate	0.0714533	0.0711460

SECTION III. DEFINITIONS

This page intentionally left blank

1. ANCILLARY SERVICES

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

- a. Scheduling, System Control, and Dispatch
- b. Reactive Supply and Voltage Control from Generation Sources
- c. Regulation and Frequency Response
- d. Energy Imbalance
- e. Operating Reserve – Spinning
- f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. BALANCING AUTHORITY AREA

See definition in Control Area.

3. BILLING FACTOR

The Billing Factor is the quantity to which the rate specified in the rate schedule is applied. When the rate schedule includes rates for several products, there may be a Billing Factor for each product.

4. CONTROL AREA

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
- b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

- a. Regulation and Frequency Response Service
- b. Generation Imbalance Service
- c. Operating Reserve – Spinning Reserve Service
- d. Operating Reserve – Supplemental Reserve Service
- e. Variable Energy Resource Balancing Service
- f. Dispatchable Energy Resource Balancing Service

6. DAILY SERVICE

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.

7. DIRECT ASSIGNMENT FACILITIES

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA for the sole use and benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Federal Energy Regulatory Commission policy. Direct Assignment Facilities shall be specified in the service agreement that governs service to the Transmission Customer.

8. DIRECT SERVICE INDUSTRY (DSI) DELIVERY

The DSI Delivery segment consists of equipment necessary to deliver power to DSI customers at low voltages (i.e., 6.9 or 13.8 kV).

9. DISPATCHABLE ENERGY RESOURCE

For purposes of the ACS rate schedule, a Dispatchable Energy Resource is any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

10. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

11. DYNAMIC SCHEDULE

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. DYNAMIC TRANSFER

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

13. EASTERN INTERTIE

The Eastern Intertie is the segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

14. ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

15. FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM

The Federal Columbia River Transmission System (FCRTS) is the transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

16. FEDERAL SYSTEM

The Federal System is the generating facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

- a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability ("BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer that may be scheduled by BPA);
- b. that BPA may use under contract or license; or
- c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

17. GENERATION IMBALANCE

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

18. GENERATION IMBALANCE SERVICE

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

19. HEAVY LOAD HOURS (HLH)

Heavy Load Hours (HLH) are all those hours in the period beginning with the hour ending 7 a.m. through hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable), except for holidays recognized by NERC.

20. HOURLY NON-FIRM SERVICE

Hourly Non-firm Service is non-firm transmission service under Part II of the Open Access Transmission Tariff in hourly increments.

21. INTEGRATED DEMAND

Integrated Demand is the quantity derived by mathematically "integrating" kilowatthour deliveries over a 60-minute period. For one-way dynamic schedules, demand is integrated on a rolling ten-minute basis.

22. LIGHT LOAD HOURS (LLH)

Light Load Hours (LLH) are all those hours in the period beginning with the hour ending 11 p.m. through hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

BPA considers as LLH six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that a holiday falls on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If a holiday falls on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

23. LONG-TERM FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Long-Term Firm Point-to-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of one year or more.

24. MAIN GRID

As used in the FPT rate schedule, the Main Grid is that portion of the Network facilities with an operating voltage of 230 kV or more.

25. MAIN GRID DISTANCE

As used in the FPT rate schedules, Main Grid Distance is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

26. MAIN GRID INTERCONNECTION TERMINAL

As used in the FPT rate schedules, Main Grid Interconnection Terminal refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

27. MAIN GRID MISCELLANEOUS FACILITIES

As used in the FPT rate schedules, Main Grid Miscellaneous Facilities refers to switching, transformation, and other facilities of the Main Grid not included in other components.

28. MAIN GRID TERMINAL

As used in the FPT rate schedules, Main Grid Terminal refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

29. MEASURED DEMAND

The Measured Demand is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA under the applicable transmission rate schedule. If transmission service to a point of delivery or from a point of receipt is provided under more than one rate schedule, the portion of the measured quantities assigned to any rate schedule shall be as specified by contract. The portion of the total Measured Demand so assigned shall be the Measured Demand for transmission service for each transmission rate schedule.

30. METERED DEMAND

Except for dynamic schedules, the Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered (received) for a transmission customer:

- a. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;
- b. during each time period specified in the applicable rate schedule; and
- c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accord with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the customer.

For one-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest ten-minute moving average of the load (generation) at the point of delivery (receipt). The ten-minute moving average shall be assigned to the hour in which the ten-minute period ends. For two-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest instantaneous value of the Dynamic Schedule during the hour.

31. MONTANA INTERTIE

The Montana Intertie is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

32. MONTHLY SERVICE

Monthly Service is service that starts at 00:00 on any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

33. MONTHLY TRANSMISSION PEAK LOAD

Monthly Transmission Peak Load is the peak loading on the Federal Transmission System during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.

34. NETWORK

The Network consists of facilities that transmit power from Federal and non-Federal generation sources, from interconnections with other utilities, or from the interties, to the load centers of BPA's transmission customers in the Pacific Northwest, to interconnections with other utilities, or to other segments (*e.g.*, an intertie or delivery segment).

35. NETWORK INTEGRATION TRANSMISSION (NT) SERVICE

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

36. NETWORK LOAD

Network Load is the load that a Network Customer designates for Network Integration Transmission Service under Part III of the Open Access Transmission Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service that may be necessary for such non-designated load.

37. NETWORK UPGRADES

Network Upgrades are modifications or additions to transmission-related facilities that support the BPA Transmission System for the general benefit of all users of such Transmission System.

38. NON-FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Non-Firm Point-To-Point Transmission Service is Point-To-Point Transmission Service under the Open Access Transmission Tariff that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption as set forth in section 14.7

under Part II of the Tariff. Non-Firm PTP Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

39. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer’s or Control Area Service Customer’s obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer’s or Control Area Service Customer’s obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. OPERATING RESERVE REQUIREMENT

Operating Reserve Requirement is a party’s total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, “Contingency Reserve Sharing Procedure,” and WECC Standards.

42. PERSISTENT DEVIATION

A Persistent Deviation event is one or more of the following:

a. **For Generation Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. **For Energy Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

43. POINT OF DELIVERY (POD)

A Point of Delivery is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by BPA will be made available to the Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other

BPA transmission service agreements. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

44. POINT OF INTEGRATION (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point.

45. POINT OF INTERCONNECTION (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected. This term is used in certain pre-Open Access Transmission Tariff service agreements and has the same meaning as “Point of Integration” and “Point of Receipt.”

46. POINT OF RECEIPT (POR)

A Point of Receipt is a point of interconnection on the BPA Transmission System where capacity and energy will be made available to BPA by the Delivering Party under Parts II and III of the Open Access Transmission Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

47. RATCHET DEMAND

The Ratchet Demand in kilowatts or kilovars is the maximum demand established during a specified period of time during or prior to the current billing period. The Ratchet Demand shall be the maximum demand established during the previous 11 billing months. If a Transmission Demand has been decreased pursuant to the terms of the transmission agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

48. REACTIVE POWER

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power Demand is expressed in kilovars or kVAr, and Reactive Power Energy is expressed in kilovarhours or kVArh.

49. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA’s transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA’s transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA transmission

facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA. The Transmission Customer must purchase this service from BPA.

50. REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

51. RELIABILITY OBLIGATIONS

Reliability Obligations are the obligations that a party with resources or loads in the BPA Control Area must provide in order to meet minimum reliability standards. Reliability Obligations shall be determined consistent with applicable NERC, WECC, and NWPP standards. BPA offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

52. RESERVED CAPACITY

Reserved Capacity is the maximum amount of capacity and energy that BPA agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to accommodate (i) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or (ii) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The

supplemental Control Area service response shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

53. SCHEDULED DEMAND

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

54. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

Scheduling, System Control, and Dispatch Service is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from BPA.

55. SECONDARY SYSTEM

As used in the FPT rate schedules, Secondary System is that portion of the Network facilities with an operating voltage greater than or equal to 69 kV and less than 230 kV.

56. SECONDARY SYSTEM DISTANCE

As used in the FPT rate schedules, Secondary System Distance is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

57. SECONDARY SYSTEM INTERCONNECTION TERMINAL

As used in the FPT rate schedules, Secondary System Interconnection Terminal refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

58. SECONDARY SYSTEM INTERMEDIATE TERMINAL

As used in the FPT rate schedules, Secondary System Intermediate Terminal refers to the first and last terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

59. SECONDARY TRANSFORMATION

As used in the FPT rate schedules, Secondary Transformation refers to transformation from Main Grid to Secondary System facilities.

60. SHORT-TERM FIRM POINT-TO-POINT (PTP) TRANSMISSION SERVICE

Short-Term Firm Point-To-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service with a duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

61. SOUTHERN INTERTIE

The Southern Intertie is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500-kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500-kV AC line from Buckley Substation to Summer Lake Substation; and the 500-kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000-kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

62. SPILL CONDITION

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

63. SPINNING RESERVE REQUIREMENT

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

64. STATION CONTROL ERROR

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

65. SUPER FORECAST METHODOLOGY

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. SUPPLEMENTAL RESERVE REQUIREMENT

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area. The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

67. TOTAL TRANSMISSION DEMAND

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

68. TRANSMISSION CUSTOMER

A Transmission Customer is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that (i) executes a Service Agreement, or (ii) requests in writing that BPA file with the Commission a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. In addition, a Transmission Customer is an entity that has executed any other transmission service agreement with BPA.

69. TRANSMISSION DEMAND

Transmission Demand is the maximum amount of capacity BPA agrees to make available to transmit energy for the Transmission Customer over the BPA Transmission System between the Point(s) of Integration/Interconnection/Receipt and the Point(s) of Delivery.

70. TRANSMISSION PROVIDER

A Transmission Provider, such as BPA, owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Open Access Transmission Tariff and other agreements.

71. UTILITY DELIVERY

The Utility Delivery segment consists of facilities and equipment that transform and deliver energy to a utility's distribution system at (or close to) the utility's prevailing distribution voltage.

72. VARIABLE ENERGY RESOURCE

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

73. VARIABLE ENERGY RESOURCE BALANCING SERVICE

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

74. WEEKLY SERVICE

Weekly Service is service that starts at 00:00 on any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

This page intentionally left blank.

