

BP-22 Rate Proceeding

**ADMINISTRATOR'S
FINAL RECORD OF DECISION**

BP-22-A-02

July 2021



ADMINISTRATOR'S PREFACE

Maintaining agility is critical to enable the Bonneville Power Administration (BPA) to be competitive in the evolving marketplace and is central to our mission, to our strategy, and to the Northwest's clean energy future. Today I am adopting rates based on a settlement agreement that supports BPA's competitiveness and meets its statutory obligations, while acknowledging the need for sustainable capital funding and debt-management approaches.

This settlement would not have been possible without the collaborative approach of rate case parties who presented proposals and worked with BPA staff to develop widely accepted settlement terms on controversial issues. Most significantly, the settlement agreement will provide revenue financing to strengthen BPA's financial health while limiting the amount to \$40 million per year for power rates and \$40 million per year for transmission rates.

The effect of the settlement on power rates is remarkable in that it is one of the only times in BPA's history when the average power rate will decrease compared to current levels. The average power rate decrease is 2.5 percent. Notably, this means our annual 10-year rate trajectory is less than 2 percent, which is in line with historical inflation rates. This demonstrates the effectiveness of our cost discipline and continued efforts to bend the cost curve.

For transmission rates, the settlement results in a weighted average transmission rate increase of 6.1 percent relative to current rates, which is roughly half the weighted average increase cited in the BP-22 Initial Proposal.

Revenue financing is a tool BPA included in the BP-22 Initial Proposal as a way to fund capital work and reduce outstanding debt. The settlement reduces the amount of revenue financing, relative to the Initial Proposal, in recognition of the near-term financial impacts of the pandemic on communities served by BPA's utility customers. The settlement also commits us to holding a public process on BPA's long-term financial health, including access-to-capital issues, sustainable capital funding approaches and debt management.

Another important topic in this rate case – one that also impacts BPA's competitiveness – is the Western Energy Imbalance Market (Western EIM). The final rate proposal includes rate allocations and rate schedule provisions that position BPA to be able to participate in the Western EIM during the BP-22 rate period. These rate proposals are an essential step toward preparing BPA and its customers for potential Western EIM participation. I will make a final decision about joining the Western EIM later this summer after we complete our fifth and final phase of the Western EIM decision process. No matter my decision on the Western EIM, the strides we have made through this rate case to enable BPA's EIM participation reflect our ongoing commitment to modernizing systems and processes to maximize the value of the region's federal power and transmission assets.

I greatly appreciate the time and effort that all parties devoted to the BP-22 proceeding and settlement discussions. I also want to thank our Federal partners, Energy Northwest, and other regional partners for their continued support of BPA's cost-management goals, as

well as the BPA workforce, for their collaborative spirit, stewardship, and commitment to our agency's mission.

I look forward to working together with our customers and strategic partners to help strengthen the region's economic prosperity and environmental sustainability through this next rate period and beyond.

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Under separate cover:

Appendix B: 2022 Power Rate Schedules and General Rate Schedule Provisions (BP-22-A-02-AP01)

Appendix C: 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (BP-22-A-02-AP02)

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental

DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
Hz	Hertz
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie

inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
KSI	key strategic initiative
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service

NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
OATT	Open Access Transmission Tariff
OCBR	Operational Controls for Balancing Reserves
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PMA	Power Marketing Administration
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
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RBC	Reliability-based control
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision

RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES

Party Abbreviations

AC	Avista Corporation
AR	Avangrid Renewables, LLC
AW	Alliance of Western Energy Consumers
BC	Benton County Public Utility District No. 1
BR	Brookfield Renewable Trading and Marketing LP
CP	Calpine Corporation
ED	EDP Renewables North America LLC
FR	Franklin County Public Utility District No. 1
ID	Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United
IN	Invenergy LLC
IP	Idaho Power Company
JP01	NI, RN
JP02	EW, SN
JP03	AR, AC, PC, and PS
JP04	AC, PC, IP, PS, and PG
LA	Los Angeles Department of Water and Power
MS	M-S-R Public Power Agency
NE	NorthWestern Corporation
NI	Northwest & Intermountain Power Producers Coalition
NR	Northwest Requirements Utilities
NS	NewSun Energy Transmission Company LLC
NW	Northwest Irrigation Utilities
PC	PacifiCorp
PG	Portland General Electric Company
PN	Pacific Northwest Generating Cooperative
PP	Public Power Council
PS	Puget Sound Energy, Inc.
PX	Powerex Corporation
RN	Renewable Northwest
SE	City of Seattle
SH	Shell Energy
SN	Snohomish County Public Utility District No. 1
TA	City of Tacoma
TC	TransAlta Energy Marketing (U.S.)
UE	Umatilla Electric Cooperative
WG	Western Public Agencies Group *

* The Western Public Agencies Group (“WPAG”) petition for leave to intervene states that each of the utilities that comprise WPAG individually file the petition requesting leave to intervene. These utilities are Eugene Water & Electric Board; Benton Rural Electric Association; the Cities of Port Angeles, Ellensburg and Milton, Washington; the Towns of Eatonville and Steilacoom, Washington; Alder Mutual Light Company; Elmhurst Mutual Power and Light Company; Ohop Mutual Light Company; Lakeview Light and Power Company; Parkland Light and Water Company; Public Utility Districts No. 1 of Clallam, Clark, Cowlitz, Grays Harbor, Kittitas, Lewis, Mason, and Skamania Counties, Washington; Public Utility District No. 3 of Mason County, Washington; and Public Utility District No. 2 of Pacific County, Washington.

Joint Party Designation Codes

Party Code	Joint Party	Joint Party Members
JP01	Joint Party 1	Northwest & Intermountain Power Producers Coalition (NI) Renewable Northwest (RN)
JP02	Joint Party 2	Eugene Water & Electric Board (part of WPAG) Snohomish County Public Utility District No. 1 (SN)
JP03	Joint Party 3	Avangrid Renewables, LLC (AR) Avista Corporation (AC) PacifiCorp (PC) Puget Sound Energy, Inc. (PS)
JP04	Joint Party 4	Avista Corporation (AC) PacifiCorp (PC) Idaho Power Company (IP) Puget Sound Energy, Inc. (PS) Portland General Electric Company (PG)

1.0 GENERAL TOPICS

1.1 Introduction

This Final Record of Decision (ROD) contains the decisions of the Administrator of the Bonneville Power Administration (BPA) based on the record compiled in this proceeding with respect to the adoption of Power, Transmission, and Ancillary and Control Area Service rates for the two-year rate period of October 1, 2021, through September 30, 2023 (fiscal years (FY) 2022–2023). The rate schedules and General Rate Schedule Provisions (GRSPs) established in this proceeding will replace existing rate schedules and GRSPs that expire on September 30, 2021.

The BP-22 rate proceeding has included an evidentiary hearing, submission of written briefs by the parties, and publication of a Draft ROD. This Final ROD provides background information, addresses the issues raised in the parties' briefs, responds to participant comments submitted during the public comment period, and summarizes BPA's assessment of the potential environmental effects of implementation of the FY 2022-2023 rates consistent with the National Environmental Policy Act (NEPA).

1.2 Procedural History

1.2.1 Workshops Prior to the BP-22 Rate Proceeding

Beginning in the fall of 2019, BPA sponsored a series of public workshops and other meetings to discuss certain topics related to power and transmission rates before the start of the BP-22 rate proceeding and the release of BPA's Initial Proposal. BPA designed the workshops to allow its Staff and interested parties to develop a common understanding of specific topics, generate ideas, and discuss alternative proposals.

In 2019, BPA held workshops on October 23, November 19, and December 12. In 2020, BPA held workshops on January 28, February 25, March 17, April 10 and 28, May 19, June 23 and 24, July 28, 29 and 30, August 25 and 26, September 29, October 7, and November 4 and 12.

Customers led workshops on the following dates in 2020: January 15, February 18, March 11, May 13, June 10, July 15, August 12, and September 1 and 9.

1.2.2 BP-22 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 of Procedure, which were published in the Federal Register, 83 Fed. Reg. 39,993 (Aug. 13, 2018), and posted on BPA's website at <https://www.bpa.gov/Finance/RateCases/>

[RulesProcedure/Pages/default.aspx](#). The Rules of Procedure implement the Section 7(i) requirements.

On December 1, 2020, BPA published notice of the BP-22 rate proceeding in the Federal Register. “Fiscal Year (FY) 2022–2023 Proposed Power and Transmission Rate Adjustments[,] Public Hearing and Opportunities for Public Review and Comment,” 85 Fed. Reg. 77,189 (Dec. 1, 2020). The rate proceeding began with a prehearing conference on December 7, 2020. After the prehearing conference, the Hearing Officer issued orders establishing the schedule for the rate proceeding, special rules of practice, and granted petitions to intervene.

BPA’s Initial Proposal for FY 2022-23 power and transmission rates was supported by Staff’s studies and written testimony issued on December 7, 2020. A Clarification session for questions about the Initial Proposal was held on December 17, 2020. BPA Staff filed supplemental testimony on December 18, 2020; no party requested clarification regarding this additional testimony. The parties filed direct testimony on February 3, 2021. Clarification of parties’ direct testimonies was held on February 9, 2021. BPA Staff and the parties filed rebuttal testimony on March 16, 2021. The litigants did not elect clarification of the rebuttal testimony.

BPA Staff and the parties elected not to conduct cross-examination, and the hearing scheduled for April 8 and 9, 2021, was cancelled.

On April 7, 2021, BPA received settlement proposals from multiple parties and subsequently held settlement conferences on April 14, 20, and 28, 2021. The settlement discussions resulted in a proposed Settlement Agreement for Rates for Fiscal Years 2022-23 (Settlement), which BPA Staff filed with the Hearing Officer on April 29, 2021. The Settlement is attached as Appendix A and described in more detail in Chapter 2 of this Final ROD. The Hearing Officer established a deadline of May 5, 2021, for any party to file an objection to the Settlement and identify any issues that the party intended to contest. Order Modifying Procedural Schedule and Establishing Deadline for Objections to Settlement, BP-22-HOO-17, at 1. Any party that did not file an objection would waive its right to contest the Settlement in Initial Briefs.

Although most parties did not file objections in response to the Hearing Officer’s order, Brookfield Renewable Trading and Marketing LP (Brookfield), Idaho Power Company, NewSun Energy Transmission Company LLC, NorthWestern Corporation, and a joint party consisting of Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United (collectively, the Environmental Parties) all submitted timely filings objecting to or stating concerns with some aspect of the Settlement. Objection of Brookfield Renewable Trading and Marketing LP to BP-22 Settlement Agreement, BP-22-M-BR-04; Answer and Limited Objection to the Motion of BPA to Modify Procedural Schedule and Establish Deadline for Objections to the Settlement Agreement of Idaho Power Company, BP-22-M-IP-02; Objection to Settlement of NewSun Energy Transmission Company, LLC, BP-22-M-NS-01; NorthWestern Corporation’s Limited Exception to Section 3 of the Settlement Agreement, BP-22-M-NE-02; Notice of Objection to Settlement

Proposal, BP-22-M-ID-04. Given the limited number and scope of the objections, Staff moved forward with recommending adoption of the Settlement despite the opposition.

Brookfield and the Environmental Parties filed initial briefs on May 11, 2021. None of the parties requested oral argument before the Administrator, and oral argument that had been scheduled for May 18, 2021, was cancelled. The Draft ROD was issued on June 25, 2021. The Environmental Parties filed a brief on exceptions on July 9, 2021.

Certain parties to this proceeding consolidated for the purpose of filing joint testimony or briefs on one or more issues. *See* Rules of Procedure § 1010.7. The rate case clerk assigned each joint party an alphanumeric designation (JP01, JP02, JP03, and JP04). For convenience, a list of the joint parties appears in the list of Party Abbreviations and Joint Party Designation Codes included at the beginning of this Final ROD. *See also* Document Numbering System and Pre-Marking of Exhibits and Briefs, BP-22-H00-02.

BPA received four written comments during the participant¹ comment period, which began with the publication of the Federal Register notice on December 1, 2020, and ended March 1, 2021. Participant comments are part of the record upon which the Administrator bases the decisions; they are summarized and addressed in Chapter 5. Participant comments may be viewed on BPA's website at <https://publiccomments.bpa.gov/CommentList.aspx?ID=405>.

1.2.3 Waiver of Issues by Failure to Raise in Briefs

Pursuant to Section 1010.17(f) of the Rules of Procedure, 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 1010.17(b) and (c) of the Rules of Procedure set forth the requirements applicable to initial briefs and briefs on exceptions. Pursuant to Section 1010.17(c) of the Rules of Procedure, a party that raises 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.

1.3 Legal Guidelines Governing Establishment of Rates

1.3.1 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

¹ For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA's Rules of Procedure provide opportunities to participate in the ratemaking process through submission of comments as "participants." *See* Rules of Procedure § 1010.8. No party may submit comments as a participant, and comments so submitted will not be included in the record. *Id.* § 1010.8(d).

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 and the other costs and expenses incurred by the Administrator under the Northwest Power Act and other provisions of law. *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. § 839e(a)(1); *see also* 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. 16 U.S.C. § 825s.

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. §§ 838g–838h, which contain 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.

1.3.2 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 N.C. v. Se. 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”); *PacificCorp 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 L.A. 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 United States Supreme Court has also recognized the deference given to the Administrator’s interpretation of the Northwest Power Act. *Aluminum Co. of Am. 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.”).

1.4 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 Federal Energy Regulatory Commission (FERC or 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, at 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, at 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’s rates. 18 C.F.R. Part 300 (1997).

1.4.1 Standard of Commission Review

The Commission reviews BPA’s 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. *See* 16 U.S.C. § 839e(a)(2)(A)-(B). 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. *See* 16 U.S.C. § 839e(a)(2)(C); *see also U.S. Dep’t of Energy – Bonneville Power Admin.*, 39 FERC ¶ 61,078, at 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.*, 735 F.2d at 1115.

1.5 Related Topics and Processes

This section includes a 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 1 (IPR 1), Integrated Program Review 2 (IPR 2), the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement), and the Rate Period High Water Mark (RHWM) Process. Issues

related to those processes are outside the scope of the BP-22 rate proceeding. 85 Fed. Reg. at 77,190-91 (Dec. 1, 2020).

1.5.1 Spending Review

Since 1986, in a process separate from its rate proceedings, BPA has conducted a public review of planned expense and capital spending levels used in the development of rates, now known as the Integrated Program Review (IPR). This process provides interested parties the opportunity to review and provide comment on all of BPA's program expense and capital spending level estimates prior to the use of those estimates in setting rates.

In June 2020, BPA held a series of public workshops to review the proposed program expense and capital spending to be the basis for power and transmission rates in the BP-22 rate proceeding. This combined process provided opportunities for the public to review and comment on power, transmission, and agency service expense programs, and included detailed review of asset strategies and associated capital spending levels.

In October 2020, BPA issued a Closeout Report for the IPR 1 (IPR 1 Closeout Report), in which BPA responded to public comments. In the report, BPA established the program expense and capital spending level estimates that were used in the BP-22 Initial Proposal to establish the proposed power and transmission rates. A few days before issuance of the IPR 1 Closeout Report, BPA and other action agencies issued the Final Record of Decision on the Columbia River System Operations (CRSO) Environmental Impact Statement (EIS) and associated Endangered Species Act (ESA) consultations (*available at* <https://www.nwd.usace.army.mil/CRSO/>). In light of this decision, BPA committed in the IPR 1 Closeout Report to “conduct a second IPR [IPR 2] in the early part of 2021 and [to] provide more details in the upcoming months.” IPR 1 Closeout Report at i, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2020IPR/20201019-BP22-Final%20Close-out.pdf>. Following publication of the IPR 1 Closeout Report, stakeholders also asked for further discussion of the Transmission direct capital program and facilities spending. On February 12, BPA notified regional parties of the commencement of IPR 2 and announced a workshop for March 2, 2021. At that workshop, BPA addressed its capital spending and execution plan for the Transmission and facilities asset categories and the impacts of the CRSO EIS and associated ESA consultations. Following the March 2 workshop, BPA opened a three-week comment period. On April 27, 2021, BPA issued the IPR 2 Closeout Report, in which BPA reduced its projected Transmission capital spending and confirmed that its fish and wildlife spending estimates from the IPR 1 Closeout Report remained sufficient to meet its environmental obligations for the rate period. IPR 2 Closeout Report, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2020IPR/20210430-IPR%20Cose-Out-Letter-Report.pdf>.

1.5.2 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), through 2028. 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).

1.5.3 Rate Period High Water Mark Process

BPA has established FY 2022–2023 RHWMs for customers with Contract High Water Mark (CHWM) contracts. In the RHWM Process, which preceded the BP-22 rate proceeding and concluded in September 2020, BPA established the maximum planned amount of power a customer is eligible to purchase at Priority Firm Tier 1 rates during the rate period, the Above-RHWM Load 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 ratemaking purposes.

1.5.4 Energy Imbalance Market

Since 2018, BPA has been exploring with regional stakeholders whether to join the California Independent System Operator (CAISO) Energy Imbalance Market (EIM). Mantifel *et al.*, BP-22-E-BPA-30, at 5. The EIM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating resources to balance supply, transfers between Balancing Authority Areas (BAAs) (interchange), and load across the market's footprint. *Id.* at 2. For balancing authorities in the EIM (EIM entities), the EIM is integrated into the Energy Imbalance and Generation Imbalance services provided by the EIM entities under their respective Open Access Transmission Tariffs (OATTs). Imbalance in the EIM is settled using Locational Marginal Pricing (LMP).

To decide whether to join the EIM, BPA developed a five-phase process, described in detail in the Administrator's Record of Decision, Energy Imbalance Market Policy at 29–36 (Sept. 2019) (EIM Policy ROD), available at <https://www.bpa.gov/news/pubs/RecordsofDecision/rod-20190926-Energy-Imbalance-Market-Policy.pdf>. Phase I was an exploration and education phase for both BPA and its stakeholders. Mantifel *et al.*, BP-22-E-BPA-30, at 5. Phase II picked up where Phase I left off and continued to flesh out the policies and positions from Phase I, considered the business case for joining the EIM, and commenced a formal policy development process with stakeholders. *Id.* Phase III continued the policy development process, establishing BPA's initial position on EIM issues that would be decided in the BP-22 rate case and a separate, concurrent proceeding (TC-22) addressing the terms and conditions of transmission service in BPA's OATT. *Id.* at 6. Phase III also addressed four discrete issues that were not included in the BP-22 or TC-22 proceedings. *Id.* In Phase IV, BPA developed and proposed the rate schedules, cost allocations, and non-rate Tariff terms necessary to position BPA to participate in the EIM

by its target date, which is March of 2022. Phase V is the final step, during which BPA will make its final decision on whether to join the EIM. *Id.*

The rates in this BP-22 rate proceeding will be in effect from October 1, 2021, through September 30, 2023. As such, the rates developed in this BP-22 proceeding (Phase IV) must address the rate schedule language, cost allocations, and other matters related to the EIM to position BPA for EIM participation if the Administrator decides to join in Phase V. To do that, BPA developed EIM-related proposals on the functionalization of EIM startup costs (Mace *et al.*, BP-22-E-BPA-31), the allocation of EIM Charge Codes among transmission users (Pleger *et al.*, BP-22-E-BPA-32), and the allocation and estimation of EIM Charges and Credits in Power rates (Traetow *et al.*, BP-22-E-BPA-33). As explained in Chapter 2, those proposals have been adopted as part of the Settlement.

2.0 SETTLEMENT

Almost all parties in the BP-22 rate proceeding agreed not to oppose the settlement of issues reflected in the Settlement Agreement for Rates for Fiscal Years 2022-23. Appendix A; see Motion of Bonneville Power Administration to Modify Procedural Schedule and Establish Deadline for Objections to Settlement Agreement, BP-22-M-BPA-02; Order Modifying Procedural Schedule and Establishing Deadline for Objections to Settlement Agreement, BP-22-HOO-17. The Settlement was structured to require parties to file any objections on the record by a deadline or waive the right to object; it also provided non-opposing parties with the opportunity to withdraw in the event an objection was filed. Two parties, discussed below, filed objections to the Settlement and briefs stating their positions; however, no party withdrew from the Settlement as a result of the objections. The terms of the Settlement, the wide range of parties that do not object, and the rest of the record provide support for the adoption of all Power and Transmission rates at issue in this proceeding. Brookfield and the Environmental Parties (Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United) submitted briefs opposing specific aspects of the Settlement. As discussed in Issue 2.1, BPA is adopting the Settlement for the purpose of establishing rates for the FY 2022–23 rate period. The arguments of Brookfield and the Environmental Parties are noted briefly in Issue 2.1 and are addressed in detail in Chapters 3 and 4, respectively, of this Final ROD.

Issue 2.1

Whether BPA should adopt the Settlement.

Parties' Positions

Most of the parties in the BP-22 rate proceeding do not oppose adoption of the Settlement. Only two parties filed briefs opposing the Settlement.

Brookfield opposes the Settlement on the basis of the treatment of the Short Distance Discount (SDD) for Point-to-Point (PTP) transmission service on the network. Brookfield Br., BP-22-B-BR-01, at 2.

The Environmental Parties maintain that the rates under the Settlement would not provide “equitable treatment” for fish and wildlife. Environmental Parties Br., BP-22-B-ID-01, at 1; Environmental Parties Br. Ex., BP-22-R-ID-01, at 1

NorthWestern Energy, Idaho Power, and NewSun Energy Transmission submitted filings in response to the Hearing Officer’s order to specify that they did not “assent” to the terms of the Settlement, as provided in Section 3 of the agreement. NorthWestern Corporation’s Limited Exception to Section 3 of the Settlement Agreement, BP-22-M-NE-02, at 1; Answer and Limited Objection to the Motion of BPA to Modify Procedural Schedule and Establish Deadline for Objections to the Settlement Agreement of Idaho Power Company, BP-22-M-IP-02, at 1-2; Objection to Settlement of NewSun Energy Transmission Company, LLC, BP-22-M-NS-01, at 1. These parties did not file initial briefs on their positions.

BPA Staff's Position

Staff supports adoption of the Settlement notwithstanding the limited objections by Brookfield and the Environmental Parties.

Evaluation of Positions

BPA appreciates the time and effort that all parties in the BP-22 proceeding devoted to the settlement discussions. As described in Chapter 1, the development of the Settlement occurred as a result of keenly focused discussions among the litigants in a relatively short period of time. Achieving a settlement among almost all parties in a compressed timeframe, while many participants were working remotely, would not be achievable without a collaborative approach from all involved.

The settlement discussions followed the development of an extensive record through the submission of testimony and other evidence regarding a number of controversial issues in this proceeding. The Settlement includes terms explicitly addressing most of the controversial issues, including Power and Transmission revenue financing, Transmission losses, EIM costs and benefits, balancing services, and the Transmission utility delivery charge. Appendix A (Settlement), Attachment 1, §§ 1-6. Other issues are settled consistent with Staff's Initial Proposal, as modified by any changes in Staff's rebuttal testimony. *Id.* § 7. The Settlement also includes a number of commitments about future public processes for additional discussion of issues raised by the parties in this proceeding. *Id.* §§ 1-4, 6.

As part of the terms of the Settlement, parties that did not file an objection on the record cannot contest adoption of the agreement in the BP-22 Proceeding, or other forums, or the implementation of the Settlement pursuant to its terms, through the end of FY 2023. Given the number of contested issues reflected in the extensive evidentiary record in this proceeding, the Settlement has helped eliminate the need for most parties to submit briefs on most of the issues, and it will avoid the potential for further dispute about those issues before FERC or the Ninth Circuit Court of Appeals. BPA places significant weight on the benefits of adopting an outcome that reflects a compromise and at least some degree of consensus among most parties. *See Van Bronkhorst v. Safeco Corp.*, 529 F.2d 943, 950 (9th Cir. 1976) (it "hardly seems necessary to point out that there is an overriding public interest in settling and quieting litigation.").

In addition to helping narrow the scope of and eliminate the potential for further dispute about certain contested issues in this proceeding, the Settlement also helps set the stage for discussion of those issues in the future. The public process commitments provide assurance that BPA Staff and stakeholders will have a forum for collaborative discussion of issues that may have been the subject of compromise in the Settlement. The benefit associated with the continuation of discussion of certain issues outside of the confines of the rate case process provides additional justification for adoption of the Settlement despite the objections.

BPA acknowledges that the Settlement does not enjoy unanimous support from all parties, but the limited and relatively discrete objections raised by Brookfield and the

Environmental Parties provide an insufficient basis to reject a reasonable and negotiated outcome for rates and other issues. Chapters 3 and 4 of this Final ROD address Brookfield's and the Environmental Parties' specific arguments in detail. The record in this proceeding demonstrates that the proposed rates under the Settlement satisfy the statutory directives that apply to BPA ratemaking, and the Settlement provides a reasonable basis for the adoption of those rates for the FY 2022-23 rate period. *See Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939, 967 (9th Cir. 2013) ("So long as the Settlement complies with the relevant statutory authority . . . BPA does not need its customers to unanimously agree to the rates it sets in accordance with the Settlement.").

Decision

The Settlement is adopted for the purpose of establishing BPA rates for the FY 2022-23 rate period.

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3.0 TRANSMISSION RATES SHORT-DISTANCE DISCOUNT

The Short Distance Discount (SDD) provides a reduction to certain rates for transmission service on the Network segment when the reservation or designated network resource for the service uses less than 75 circuit miles of the Federal Columbia River Transmission System (FCRTS). 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-E-BPA-11, NT-22, § IV.D, PTP-22, § IV.F. Under the Settlement, BPA Staff proposes to retain the SDD in its current (BP-20) form with certain clarifying revisions Staff recommended in rebuttal testimony. Fredrickson *et al.*, BP-22-E-BPA-44, at 3. Brookfield Renewable Trading and Marketing LP opposes this aspect of the Settlement and has proposed changes to the way that BPA treats “redirects” of PTP reservations under the SDD. Greenleaf, BP-22-E-BR-01; Brookfield Br., BP-22-B-BR-01.

Issue 3.1

Whether BPA should change the way it applies the SDD when there are redirects of PTP reservations.

Parties’ Positions

Brookfield requests the Hearing Officer to decline the Settlement and instead order BPA to adopt revisions to the rate schedule language that would change the way the SDD applies to redirects of PTP service.² Brookfield Br., BP-22-B-BR-01, at 2.

BPA Staff’s Position

Consistent with the proposed Settlement, BPA Staff recommends adopting the clarifying revisions to the PTP rate schedule that Staff proposed in rebuttal testimony. Fredrickson *et al.*, BP-22-E-BPA-44, at 3.

Evaluation of Positions

Brookfield asks the Hearing Officer to order BPA to include Brookfield’s recommended language in the SDD rate and to develop a more efficient billing mechanism for the SDD. Brookfield Br., BP-22-B-BR-01, at 9-10. Pursuant to BPA’s Rules of Procedure, the Hearing Officer “is responsible for conducting the proceeding, managing the development of the Record, and resolving procedural matters.” Rules of Procedure § 1010.3(a). The Hearing Officer only recommends a decision in a proceeding “revising or establishing terms and conditions of general applicability for transmission service . . . pursuant to Section 212(i)(2)(A) of the Federal Power Act . . .” *Id.* §§ 1010.1(a)(2), 1010.3(a). In a rate proceeding under Section 7(i) of the Northwest Power Act, the Hearing Officer cannot recommend a decision or outcome to the Administrator.

² Brookfield refers to BPA’s Tariff in its initial brief, but BPA does not include rates in its Tariff. To the extent that Brookfield would like to propose tariff language, the appropriate forum would be a future proceeding to change the terms and conditions of BPA’s Tariff.

For a customer with a PTP reservation that uses less than 75 circuit miles of the FCRTS, the SDD effectively reduces the rate the customer pays for its service. See 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-E-BPA-11, PTP-22, § IV.F. BPA adopted the SDD to create an incentive for customers to choose generation close to load and to discourage the construction of alternative facilities over short distances. Fredrickson *et al.*, BP-22-E-BPA-44, at 2.

Under BPA's Open Access Transmission Tariff (OATT), a customer has the option to request to "redirect" a PTP reservation from the original contract point of receipt or delivery to a different point on the system. BPA OATT, TC-20-A-03, Appendix 1, Attachment 2, § 22.1. If a customer receives the SDD on a PTP transmission reservation and then elects to redirect that reservation for all or a portion of a month, the customer loses the SDD for that month. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-E-BPA-11, PTP-22, § IV.F. If the SDD is removed for a month, the customer is charged the regular rate for service.

Brookfield recommends revisions to the proposed PTP-22 rate schedule language that would change the existing SDD by eliminating only the portion of the discount that corresponds to the amount of capacity and duration of a redirect or redirects during the month. Brookfield Br., BP-22-B-BR-01, at 2, 9. Brookfield asserts several arguments in support of its recommendation: (1) removal of the SDD for the entire month creates disparate treatment between customers; (2) removal of the SDD results in a rate other than the "lowest possible rate"; (3) removal of the SDD creates a barrier to redirecting reservations; and (4) lack of the ability to implement its proposal should not impede BPA from adopting Brookfield's recommended language. *Id.* at 5, 7, 11, 16–18.

To Brookfield's point about disparate treatment and undue discrimination, those are not standards that apply to BPA ratemaking under the Northwest Power Act. Administrator's Final Record of Decision, BP-12-A-02, at 203-05; Administrator's Final Record of Decision, BP-18-A-04, at 174. Chapter 1 of this Final ROD describes the statutory standards that govern BPA ratemaking and Commission review of BPA's rates, and the Commission has approved BPA's transmission rates under those standards many times since the SDD was adopted. See, e.g., *Bonneville Power Admin.*, 154 FERC ¶ 61,077 (2016); *Bonneville Power Admin.*, 162 FERC ¶ 61,248 (2018); *Bonneville Power Admin.*, FERC Docket No. EF19-5, Order Confirming and Approving Rates on a Final Basis (Apr. 17, 2020). In addition, the provision requiring removal of the SDD in the event of redirects has been expressly enforced in the Ninth Circuit Court of Appeals. See *PacifiCorp v. U.S. Dep't of Energy*, 772 F. App'x 570 (9th Cir. 2019) (affirming BPA's decision to recoup SDDs that had mistakenly been applied in months in which redirects occurred). BPA assigns significant weight to these previous approvals, especially when considering whether to adopt a Settlement that is both unopposed by a majority of the parties and largely maintains the SDD in its current form.

Even if Brookfield was correct about the applicability of the disparate treatment and undue discrimination standards, simply having a difference between rates that customers are charged does not create undue discrimination. Indeed, if it did, the SDD would be

problematic on its face because it grants a discount solely on the basis of the customer's use of the system in terms of circuit-mile distance.

Brookfield compares the rate for a customer that redirects a reservation during a portion of the month to the rate for a customer that leaves its reservation unchanged. Brookfield Br., BP-22-B-BR-01, at 2. When a customer redirects a PTP transmission reservation that receives the SDD in the short term, it is no longer using the path on which the discount was based. A redirected reservation no longer serves the original purposes for which the SDD was developed: to discourage customers from building around BPA's system and to incent location of generation close to load. Fredrickson *et al.*, BP-22-E-BPA-44, at 4. The treatment of the redirect may be different, but it is not unduly discriminatory because it continues to be based upon the customer's use of the transmission system and the purposes of the SDD. In addition, as described below, implementation of the SDD in the manner that Brookfield suggests is impractical in terms of the BPA systems used to administer the discount.

Brookfield maintains that removal of the SDD results in a rate other than the "lowest possible rate," which, Brookfield argues, is a statutory requirement. Brookfield Br., BP-22-B-BR-01, at 7. Brookfield is incorrect in its interpretation of the "lowest possible rates" language in BPA's statutes. The statutory requirement is that BPA set its rates "with a view to encouraging . . . the lowest possible rates to consumers . . ." 16 U.S.C. § 838g. The Ninth Circuit Court of Appeals has determined that this statutory requirement is not a "statutory command that the prices charged to consumers always be the lowest possible." *Cal. Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1308 (9th Cir. 1990). In addition, the "lowest possible rates" standard applies to BPA's rates as a whole and not particular rates (or rate discounts) in isolation. *See* 16 U.S.C. §§ 825s, 838g; Administrator's Final Record of Decision, BP-20-A-03, at 46.

Rather than a question of whether the application of the SDD to redirects results in the "lowest possible rates," the crux of the issue that Brookfield raises is a matter of rate design and cost allocation. BPA has broad discretion with respect to design and allocation of costs in transmission rates. *Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984); *Pac. Power & Light v. Bonneville Power Admin.*, 499 F. Supp. 672 (9th Cir. 1986). If BPA were to expand its application of the SDD as Brookfield suggests, it would likely increase the costs shifted between customers that receive the SDD and those that do not. The total costs that BPA recovers in its rates remain the same, regardless of the SDD. With the SDD, however, certain customers effectively pay less than the full cost of transmission service. This shifts that portion of costs to the rate for reservations that do not qualify for the SDD. The SDD has been in place for many years in its current form, and BPA is not seeking to expand its applicability, or the associated cost shifts, at this time.

Brookfield suggests that removing the SDD in one-month increments is a barrier to customers' flexibility to request redirects under BPA's OATT. Brookfield Br., BP-22-B-BR-01, at 11. In rebuttal, BPA Staff shared a different perspective: removing the SDD simply results in the customer being charged the same rate for transmission as for all other long-term reserved capacity. Fredrickson *et al.*, BP-22-E-BPA-44, at 5. BPA Staff also

provided data to show that customers with the SDD continue to redirect their reserved capacity. Motion to Admit Responses to Data Requests into Evidence, BP-22-M-BR-03, Att. 1 at 23 (BPA Response to Data Request BR-BPA-30-18). Thus, removing the SDD in one-month increments when customers redirect during the month does not create an unjust or unreasonable barrier to the flexibility to request a redirect.

Lastly, Brookfield argues that BPA Staff should be able to implement its requested changes to the SDD in the BPA billing systems and processes. Brookfield Br., BP-22-B-BR-01, at 16-18. Staff explained in rebuttal testimony that, even if the redirected reservation still uses 75 circuit miles or less of transmission, it is neither practical nor currently possible to automate removing the provision for a portion of the month or removing it for only a portion of a reservation. Fredrickson *et al.*, BP-22-E-BPA-44, at 4-5. BPA Staff indicated that implementing the requested changes would cost more than \$1 million and significant hours of Staff time. *Id.* As described above, the SDD is a discount for transmission service that was adopted to achieve specific policy and business objectives. It is not an industry standard practice, and the particular form of the SDD, including the treatment of redirects, is a matter of rate design that falls within BPA's discretion. Given the significant dedication of resources that would be required to develop and implement the changes that Brookfield suggests, further expansion and modification of this unique discount is not the best use of BPA's limited resources.

Decision

BPA adopts the SDD as proposed in the Initial Proposal with the clarifying language in the rates schedule as recommended by BPA Staff in rebuttal.

4.0 FISH & WILDLIFE ISSUES

4.1 Introduction

BPA's rates are set to recover its projected costs. One component of costs BPA must recover are projected costs for the various programs BPA supports, including actions for fish and wildlife affected by the FCRPS. *See* 16 U.S.C. § 839e(a)(1). BPA publicly shares its estimates of the projected costs for its programmatic spending in the Integrated Program Review (IPR), which is an informal stakeholder process. Mandell *et al.*, BP-22-E-BPA-46, at 3. The IPR process pulls information from various sources to develop a projection of BPA's programmatic costs for the rate period, typically two years. Stakeholders are given the opportunity to submit comments on these projections. At the close of the IPR process, BPA issues a report in which it includes projections of its future programmatic costs. BPA's cost projections from the IPR and other sources are used as the cost inputs for establishing BPA's rates for the rate period.

Although BPA's programmatic cost projections form an important part of determining BPA's rate levels, those projections do not finally decide what BPA will spend during the rate period nor limit the amount of funding for any particular program. BPA ratemaking decisions decide *how* to recover BPA's forecasted costs (*e.g.*, through rate levels, cost allocation, and rate design), not *whether* to incur a cost or *which* costs to incur. The limited role of ratemaking in influencing BPA's cost decisions applies to all of BPA's programmatic costs, including its fish and wildlife spending levels. What BPA decides to actually spend on its fish and wildlife program to meet its obligations is determined in other forums, such as when BPA awards contracts, funds various programs, and implements different actions intended to benefit fish and wildlife. Those decisions are determined outside of BPA's rate proceedings and, significantly, are not ultimately constrained by the cost inputs used in BPA's ratesetting process.

The Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United (collectively, Environmental Parties), challenge BPA's fish and wildlife funding projections, contending BPA's proposed funding levels fail to meet various statutory provisions of the Northwest Power Act. *See generally*, Environmental Parties Br., BP-22-B-ID-01. This section of the Final Record of Decision (ROD) responds to the Environmental Parties' arguments.

4.2 Issues

Issue 4.2.1

Whether the "equitable treatment" mandate of the Northwest Power Act, 16 U.S.C. § 839b(h)(11)(A)(i), applies to BPA's fish and wildlife mitigation planning budgets or spending.

Parties' Positions

The Environmental Parties argue that "BPA's Initial Proposal completely ignored the agency's 'equitable treatment' obligation . . ." Environmental Parties Br., BP-22-B-ID-01,

at 9. The Environmental Parties assert that BPA's equitable treatment obligation extends to its decisions on fish and wildlife funding. *Id.* at 5-6; *see also* Environmental Parties Br. Ex., BP-22-R-ID-01, at 2-12. The Environmental Parties contend that BPA had an obligation to explain how it met equitable treatment under Section 4(h)(11)(A)(i) of the Northwest Power Act when it formulated its fish and wildlife funding for the rate period as well as when it revised its net secondary revenue projection. *Id.* at 13-14, 20. The Environmental Parties contend that BPA's failure to consider equitable treatment at each of these points is a violation of Section 4(h)(11)(A)(i) of the Northwest Power Act.

BPA Staff's Position

This is a legal issue raised in the Environmental Parties' initial brief. *See* Mandell *et al.*, BP-22-E-BPA-46, at 2-3.

Evaluation of Positions

In large part, the Environmental Parties' initial brief relies on a foundational mistaken assumption: that the "equitable treatment" mandate of the Northwest Power Act applies to BPA's funding of fish and wildlife mitigation. *See, e.g.*, Environmental Parties Br., BP-22-B-ID-01, at 17 ("BPA has never provided a reasoned explanation for how its current fish and wildlife funding levels fit into its equitable treatment obligation, likely because BPA appears to have simply ignored its equitable treatment obligation when setting funding levels.") (emphasis omitted).

This conclusory assumption, pervasive throughout Environmental Parties' arguments, is offered without supporting authority or analysis. And it is incorrect. As explained below, the Northwest Power Act's equitable treatment mandate applies to *operations and management* actions as the plain text of the statute and relevant Ninth Circuit case law make clear. Equitable treatment does not apply to BPA's budgeting or expenditures for fish and wildlife mitigation. The Environmental Parties' legally flawed premise as to the meaning and applicability of equitable treatment undercuts each of their positions and arguments that rely on it.

The "equitable treatment" mandate arises from Section 4(h)(11) of the Northwest Power Act, which provides as follows:

(A) The Administrator and other Federal agencies responsible for *managing, operating, or regulating* Federal or non-Federal hydroelectric facilities located on the Columbia River or its tributaries shall —

(i) exercise *such responsibilities* consistent with the purposes of this chapter and other applicable laws, to adequately protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by such projects or facilities in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are *managed and operated*[.]

16 U.S.C. § 839b(h)(11)(A) (emphasis added).³ The emphasized portions of the statutory text, quoted above, are indispensable to an accurate legal interpretation of the equitable treatment mandate; they are also the portions of the mandate that Environmental Parties fail to acknowledge or address.

By its express language, subparagraph 4(h)(11)(A) applies in the context of the BPA and other federal agencies' *management* and *operation* responsibilities with respect to the federal hydropower system of the Columbia River basin – for instance, system management and operation actions such as project configuration, flow management, spill operations, and water quality management. *See, e.g.,* Columbia River System Operations Final Environmental Impact Statement (CRSO FEIS), at 2-3, *available at* <https://www.nwd.usace.army.mil/CRSO/Final-EIS/#top>; *see also* *Confederated Tribes of the Umatilla Indian Reservation v. Bonneville Power Admin.*, 342 F.3d 924, 932-33 (9th Cir. 2003) (listing management and operation actions providing equitable treatment for fish). Further, in establishing the equitable treatment mandate, 4(h)(11)(A)(i) expressly refers back to “such responsibilities” stated in subparagraph 4(h)(11)(A) and ends with a reference to the management and operation of “the system and facilities.” Therefore, the plain text of the statute places the applicability of equitable treatment squarely within the context of system operations and management. *See also* 16 U.S.C. § 839(6) (declaring a congressional purpose for the Northwest Power Act “to protect, mitigate and enhance . . . anadromous fish . . . which are dependent on suitable environmental conditions substantially obtainable from the *management and operation* of the [FCRPS] and other power generating facilities on the Columbia River and its tributaries”) (emphasis added).

The statutory context of the Northwest Power Act supports this interpretation as well. Elsewhere in the statute, Congress used language that clearly implicates BPA's funding of fish and wildlife mitigation, *see, e.g.,* 16 U.S.C. § 839b(h)(10)(A) (establishing standards and limitations for the “use [of] the Bonneville Power Administration *fund*” and “[*e*]xpensitures of the [Bonneville] Administrator”) (emphasis added), but notably omitted any comparable language from the equitable treatment mandate of Section 4(h)(11)(A)(i), which, as explained above, expressly pertains to matters of system operations and management.⁴ Clearly, Congress knows how to draft legislation that applies to an agency's exercise of funding authority when it chooses. Therefore, Congress's decision to omit any comparable

³ The U.S. Congress authorized the U.S. Army Corps of Engineers (Corps) and U.S. Bureau of Reclamation (Reclamation) to construct, operate, and maintain the Columbia River System (CRS) projects to meet multiple specified purposes, including flood risk management (FRM), navigation, hydropower production, irrigation, fish and wildlife conservation, recreation, and municipal and industrial water supply. However, not every project is authorized for all of these purposes. BPA is authorized to market and transmit the power generated by these coordinated system operations.

⁴ BPA notes that while Section 4(h)(10)(A) created the obligation for the Administrator to fund fish and wildlife mitigation consistent with the Northwest Power and Conservation Council's (Council's) Fish and Wildlife Program and the purposes of the Act, Congress did not direct BPA to demonstrate in the rate-setting process that its mitigation funding levels were “consistent with” the Council's program. The Ninth Circuit essentially disposed of this argument in *Golden Nw. Aluminum v. Bonneville Power Admin.*, where it explained that “we understand that the [] rate case was not the forum for making decisions regarding which fish and wildlife alternative to implement . . .” *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007).

language regarding funding considerations from the equitable treatment provision in Section 4(h)(11)(A) must bear significance. See *SEC v. McCarthy*, 322 F.3d 650, 656 (9th Cir. 2003) (“[T]he use of different words or terms within a statute demonstrates that Congress intended to convey a different meaning for those words.”).

Ninth Circuit case law further supports the construction that the equitable treatment provision applies to operations and management actions only. Indeed, the Ninth Circuit has not interpreted the equitable treatment mandate to apply to BPA’s funding of fish and wildlife mitigation in the way the Environmental Parties assert that it does. In *Nw. Env’tl. Def. Ctr. v. Bonneville Power Admin.*, 117 F.3d 1520 (9th Cir. 1997), the court considered the equitable treatment mandate in the context of decisions pertaining to system operations (namely, allocation of water between power marketing and fish and wildlife purposes). The court found that BPA’s application of equitable treatment “*on a system-wide basis* is a reasonable reading of the Northwest Power Act.” *Id.* at 1533 (emphasis added). The court went on to establish the rule that, “[w]hile each power marketing action that affects *the system* implicates the equitable treatment provision, BPA may properly exercise its obligation by insuring equitable treatment for fish *on a system-wide basis.*” *Id.* at 1533-34 (emphasis added); see also *id.* at 1534 (considering equitable treatment in the context of system operations: “BPA need not undertake an equitable treatment analysis for every discrete *power marketing* decision”) (emphasis added). Thus, the Ninth Circuit has concluded that BPA “may properly exercise” its equitable treatment obligation through a balancing of system operations and management actions, and without regard to expenditures for fish and wildlife mitigation under a separate provision of the Northwest Power Act. Later, in *Confederated Tribes of the Umatilla Indian Reservation v. Bonneville Power Admin.*, 342 F.3d 924 (9th Cir. 2003), the Ninth Circuit again considered equitable treatment in the context of system operations and concluded that BPA provided a reasonable explanation of its fulfillment of the equitable treatment on a system-wide basis.

BPA’s interpretation of Section 4(h)(11)(A) also comports with the legislative history of the Northwest Power Act, where Representative Dingell described the objective of 4(h)(11)(A) as “insur[ing] that the *capabilities of each power project* are fully utilized to *provide operations* that are compatible with the purposes of this legislation and . . . treat[ing] fish and wildlife as a coequal partner with *other uses in the management and operation of the hydro projects* of the region.” 126 Cong. Rec. 31,435 (1980) (emphasis added). Although this statement was made in the context of Representative Dingell’s clarification that Section 4(h)(11)(A) applies to FERC as well, it offers contextual evidence of the types of actions that Congress intended to subject to the equitable treatment provision – that is, actions within the capabilities of the hydro projects themselves.

In short, the plain text of the equitable treatment provision, its context in the Northwest Power Act, and relevant case law all show that the mandate applies only to, and can be adequately fulfilled by, system operations and management actions. Therefore, the Environmental Parties’ presumption that the mandate extends to expenditures for fish and wildlife is not supported in law. See also Columbia River System Operations Environmental Impact Statement (CRSO EIS) ROD § 5.5.1, available at <https://www.nwd.usace.army.mil/CRSO/> (“The equitable treatment provision of the Act specifically applies to the co-lead

agencies' responsibilities for (1) 'managing [and] operating' (2) the federal dam and reservoir projects themselves, including the CRS."); CRSO FEIS, § 5.2.1 at 5-6 ("Equitable treatment in CRS management and operations does not create an obligation on [BPA] to allocate mitigation funds proportionately among entities, regions, or fish and wildlife resources.").⁵ The Environmental Parties' arguments that incorporate this legally flawed premise fail.

In their Brief on Exceptions, the Environmental Parties dispute BPA's interpretation of Section 4(h)(11)(A) of the Northwest Power Act, and ask the agency to part ways with its longstanding interpretation. BPA's interpretation of Section 4(h)(11)(A) is reflected in its Ninth Circuit briefing as early as 1993 in *Nw. Env'tl. Def. Ctr.* BPA affirmed its interpretation as recently as September 2020 in the CRSO EIS ROD.⁶ Environmental Parties Br. Ex., BP-22-R-ID-01, at 3-12. BPA is not persuaded that the Environmental Parties' reading of the relevant statutory provisions is more plausible than its own, or that BPA's interpretation suffers from the defects that the Environmental Parties claim. Therefore, and for the reasons explained further below, BPA will not abandon its reasonable interpretation of Section 4(h)(11)(A).

In essence, the Environmental Parties argue that there is no plausible explanation for including BPA in Section 4(h)(11)(A)⁷ unless that provision's terms apply, implicitly, to BPA's separate fish and wildlife funding responsibilities under Section 4(h)(10)(A).⁸ To reach this conclusion, the Environmental Parties rely on an attenuated chain of contextual arguments, while failing to reckon with the plain text of Section 4(h)(11)(A), which BPA has discussed above at length. See *Jimenez v. Quarterman*, 555 U.S. 113, 118 (2009) ("a question of statutory interpretation . . . begins with the plain language of the statute."); *Venezuela Gallardo v. Barr*, 968 F.3d 1053, 1063-64 (9th Cir. 2020) (examining relevant statutory context to resolve ambiguity *after* considering the text of the disputed statutory

⁵ Throughout this Final ROD, BPA references documents it produced in other forums. Since these documents are relevant to the arguments the Environmental Parties have raised, they are hereby incorporated into the record of this proceeding. See 16 U.S.C. § 839e(i)(5).

⁶ See CRSO EIS ROD § 5.5.1, available at <https://www.nwd.usace.army.mil/CRSO/> ("The equitable treatment provision of the Act specifically applies to the co-lead agencies' responsibilities for (1) 'managing [and] operating' (2) the federal dam and reservoir projects themselves, including the CRS."); CRSO FEIS, § 5.2.1 at 5-6 ("Equitable treatment in CRS management and operations does not create an obligation on [BPA] to allocate mitigation funds proportionately among entities, regions, or fish and wildlife resources.").

⁷ 16 U.S.C. § 839b(h)(11)(A) ("The Administrator and other Federal agencies responsible for managing, operating, or regulating Federal or non-Federal hydroelectric facilities located on the Columbia River or its tributaries shall – (i) [provide equitable treatment for fish and wildlife, and] (ii) [take into account the Council's program].").

⁸ 16 U.S.C. § 839b(h)(10)(A) ("The Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under this chapter and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in a manner consistent with the plan, if in existence, the program adopted by the Council under this subsection, and the purposes of this chapter.").

provision); *see also Am. Tobacco Co. v. Patterson*, 456 U.S. 63, 75 (1982) (“[g]oing behind the plain language of a statute in search of a possibly contrary congressional intent is a step to be taken cautiously even under the best of circumstances.”) (internal quotation omitted).

Specifically, the Environmental Parties argue that BPA’s interpretation of Section 4(h)(11)(A), as applying only to BPA’s system management and operations responsibilities, is “fundamental[ly] flaw[ed]” because it “eliminates any independent obligation BPA has to provide equitable treatment as well as any independent obligation to ‘tak[e] into account . . . to the fullest extent practicable’ the Council’s fish and wildlife program.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 3. This is because, the Environmental Parties claim, BPA does not have the “sole power . . . to make decisions about ‘project configurations, flow management, spill operations, and water quality management,’ as those decisions are made by the [Corps] and [Reclamation].” *Id.* Therefore, according to the Environmental Parties, Section 4(h)(11)(A)’s reference to “the Administrator” would be needless verbiage unless that provision of the statute is interpreted as extending to BPA’s separate duty to protect, mitigate, and enhance fish and wildlife through the expenditure of funds authorized by Section 4(h)(10)(A). The Environmental Parties’ reasoning and conclusion are both incorrect.

First, to be clear, the non-exhaustive list of examples of management and operations actions that BPA included in the Draft ROD (*e.g.*, “system management and operation actions such as project configuration, flow management, spill operations, and water quality management . . .”) was not meant to imply the exclusion of BPA’s power marketing actions, which BPA very much considers to be subject to Section 4(h)(11)(A). *See generally Nw. Envtl. Def. Ctr. v. Bonneville Power Admin.*, 117 F.3d 1520 (9th Cir. 1997); *Confederated Tribes*, 342 F.3d 924 (9th Cir. 2003).

Second, the Environmental Parties’ argument suffers from a self-defeating, internal inconsistency in their Brief on Exceptions. The Environmental Parties argue that BPA’s fish and wildlife funding responsibility under Section 4(h)(10)(A) *must* be subject to the provisions of Section 4(h)(11)(A) or the latter would not create “any independent obligation” for BPA. *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at 3. But the Environmental Parties later claim that the term “managing” in Section 4(h)(11)(A) *includes* power marketing, a function that BPA is “clearly empowered to perform.” *Id.* at 10-11. Indeed, there can be no dispute that BPA – a power marketing administration – is the *only one* of the federal entities involved in management of the Columbia River System authorized and responsible for marketing the power it produces. *See, e.g.*, 16 U.S.C. § 832a. Therefore, the Environmental Parties’ own interpretation of “managing” shows that Section 4(h)(11)(A) creates independent obligations for BPA with respect to its power marketing responsibilities. As such, the supposed “fundamental flaw” in BPA’s interpretation of Section 4(h)(11)(A) evaporates, and with it goes the Environmental Parties’ conclusion as to the alleged necessity of sweeping BPA’s fish and wildlife funding into the scope of Section 4(h)(11)(A).

Nonetheless, the Environmental Parties proceed to offer extensive argument for their contention that BPA does not “operate” the federal project facilities or the system.

Environmental Parties Br. Ex., BP-22-R-ID-01, at 4-8. This contention lacks merit and is irrelevant. BPA acknowledges that it is dependent on the Corps and Reclamation to ultimately implement real-time operations at the projects, and in this way those agencies are their operators in-fact; but the statute does not compel as narrow a reading as the Environmental Parties take with respect to the meaning of “operating” in the context of Section 4(h)(11)(A). Indeed, as the following context and examples demonstrate, the implementation of BPA’s power marketing responsibilities, through joint planning with the Corps and Reclamation and real-time coordination among projects, as a practical matter, results in a range of operations at the project facilities, or within the system. That practical effect is adequate to bring those actions within the ambit of Section 4(h)(11)(A). Both case law and the Environmental Parties’ actions support this point.

First, case law confirms BPA has a role under the “operations” and “management” of the FCRPS for purposes of “equitable treatment.” The Ninth Circuit has heard two equitable treatment challenges to BPA power marketing actions – including declaring a power emergency that involved curtailing fish mitigation operations at the dams. *See generally Confederated Tribes*, 342 F.3d 924; *Nw. Env’tl. Def. Ctr.*, 117 F.3d 1520. In both cases, the court found legally reviewable obligations for BPA under “equitable treatment” even though neither BPA’s ratemaking nor funding was at issue. Also, importantly, the court did not view BPA’s obligations under “equitable treatment” as tied to a finding that they sprung from an “independent obligation” that applied solely to BPA. *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at 3.

Second, the Environmental Parties’ own actions show that they generally agree that BPA has a role in the operations of the FCRPS. Two of the Environmental Parties petitioned the Ninth Circuit to review BPA’s reliance on the July 24, 2020, Biological Opinion on Columbia River System operations issued by NOAA Fisheries in deciding along with the Corps and Reclamation to operate the system following the selected alternative in the CRSO EIS.⁹ That litigation follows an earlier case in which one of the Environmental Parties, Idaho Conservation League, challenged BPA in the Ninth Circuit, individually, for a decision concerning Albeni Falls Dam operations in 2012.¹⁰ Having twice sued BPA with respect to

⁹ Petition for Review ¶ 10 (9th Cir. No. 20-73761) (Dec. 12, 2020). NOAA Fisheries issued the Biological Opinion “for the ongoing operation and maintenance of the Columbia River System (CRS) and associated non-operational measures to offset adverse effects to listed species. The three Federal Action Agencies with responsibility for operating the CRS are the Bonneville Power Administration (BPA), the U.S. Army Corps of Engineers (Corps), and the U.S. Bureau of Reclamation (BOR).” ENDANGERED SPECIES ACT SECTION 7(A)(2) BIOLOGICAL OPINION AND MAGNUSON-STEVENSON FISHERY CONSERVATION AND MANAGEMENT ACT ESSENTIAL FISH HABITAT RESPONSE FOR THE CONTINUED OPERATION AND MAINTENANCE OF THE COLUMBIA RIVER SYSTEM at 1. (July 24, 2020).

¹⁰ *See Idaho Conservation League v. Bonneville Power Admin.*, 826 F.3d 1173, 1174 (9th Cir. 2016) (“Operated by the Army Corps of Engineers (Corps), the Albeni Falls Dam helps provide power to the Pacific Northwest. The Bonneville Power Administration (BPA) is charged with marketing the power generated from the dam. In 2011, the agencies decided to change how they operated the dam during the winter months. . . .”) (emphasis added). Operations stemming from BPA’s power marketing decisions have been the subject of several other court cases as well. *See, e.g., Nw. Env’tl. Def. Ctr.*, 117 F.3d at 1520 (considering, as a matter of equitable treatment, the issue of BPA’s allocation of water between power marketing and fish purposes); *Confederated*

the agency's role in facility operations and their effects, the credibility of present arguments seeking to recast the nature of BPA's authorities, and the cases interpreting them, is diminished. BPA notes, as well, that despite their direct testimony in this rate case, acknowledging the "large role" BPA has in determining system operations, Cutter, BP-22-E-ID-01, at 3, the Environmental Parties' Brief on Exceptions significantly downplays its characterization of BPA's role. They attempt to relegate it to mere "consulting" and question "what power [BPA] has" with respect to system operations. See Environmental Parties Br. Ex., BP-22-R-ID-01, at 3, 5; Environmental Parties' Comments on IPR2 at 2 (Mar. 24, 2021), available at <https://publiccomments.bpa.gov/CommentList.aspx?ID=408> (noting "plans for operating the Federal Columbia River Power System developed by BPA and its partner agencies").

In any event, it is indeed the case, both as a practical matter and by congressional design, that BPA's exercise of its power marketing or other responsibilities—including the curtailment of power generation operations and making short-term power purchases to facilitate increased flows to improve fish habitat and spill to improve fish survival at dams, as discussed below—must result in operations at the projects. For example, the Bonneville Project Act states: "The Secretary of the Army shall schedule the operations of . . . the Bonneville project in accordance with the requirements of the [Bonneville] administrator." 16 U.S.C. § 832a(a). The CRSO FEIS expands on this dynamic: "Some requirements are established by Congress when a project is authorized, while others are established by the agencies based on operating experience. Within these operating limits, Bonneville schedules and dispatches power." CRSO FEIS § 1.4.1.

With the preceding context in mind, BPA turns now to the specifics of the Environmental Parties' substantive arguments in their interpretation of Section 4(h)(11)(A). The crux of the Environmental Parties' interpretation of Section 4(h)(11)(A) amounts to a suggestion that it *might have been* unnecessary for Congress to include a specific reference to the BPA Administrator *if* Section 4(h)(11)(A) did not extend to BPA's fish and wildlife mitigation expenditure authority, because Congress could have elected to omit the specific reference to BPA in such case. Environmental Parties Br. Ex., BP-22-R-ID-01, at 3-4, 7-8 (suggesting BPA's interpretation of Section 4(h)(11)(A) would render reference to the Administrator as "mere surplusage"). Similarly, the Environmental Parties also suggest that Section 4(h)(11)(A) must apply to fish and wildlife funding because if it does not, Congress might have chosen to express Section 4(h)(11)(A)'s mandates "in simpler terms" by excluding reference to the BPA Administrator. *Id.* at n.22.¹¹

Tribes, 342 F.3d at 928, 933 (challenging BPA declaration of power emergencies affecting the system).

¹¹ The Environmental Parties apply these same arguments with respect to Section 4(h)(11)(A)(ii). See Environmental Parties Br. Ex., BP-22-R-ID-01, at 9 ("Under BPA's view, the only 'decisionmaking processes' to which § 4(h)(11)(A)(ii) applies are decisions concerning matters 'such as project configuration, flow management, spill operations, and water quality management.' But, again, BPA lacks the legal authority to make such decisions on its own; it is thus highly unlikely that Congress would have explicitly mentioned 'the Administrator' in § 4(h)(11)(A) given that it could have achieved the same result by excluding such a mention."). BPA's responses here suffice for that argument as well.

To the first point, the mere fact that Congress might have chosen a different way to identify which agencies are subject to Section 4(h)(11)(A) does not mean that the language it ultimately chose includes any “surplusage.” To the contrary, the language Congress chose does exactly what it needs to do: identify the agencies to which the statutory provision applies, including BPA. And as to their second point, BPA questions the Environmental Parties’ apparent assumption that an alternative phrasing with slightly fewer words is necessarily “simpler,” particularly when the words to be omitted clearly specify one of the entities charged with adhering to the statutory provision. That Congress elected one of several drafting options capable of conveying the same intent does not mean the one it ultimately chose is overly complex. Moreover, this component of the Environmental Parties’ argument relies on their interpretation of alternative phrasing that Congress did *not* enact. BPA sees little value in exploring this hypothetical further.

The Environmental Parties also emphasize Congress’s delineation between the Corps’ and Reclamation’s operations responsibilities and BPA’s for power marketing, citing several pieces of legislation that establish those agencies’ operations roles. *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at 5-6. BPA does not dispute this division of responsibilities that the Environmental Parties highlight; but it does nothing to support their contention that there was no need for Congress to “single out” BPA in Section 4(h)(11)(A) other than to have its provisions apply to BPA’s fish and wildlife funding. To the contrary, there was good reason to “single out” BPA. Had Congress *omitted* the BPA Administrator from Section 4(h)(11)(A), there may well have been confusion as to whether Congress intended that provision to apply to any power marketing actions that BPA might be authorized to undertake. In this instance, then, by singling out BPA in Section 4(h)(11)(A), Congress’s intent can reasonably be understood as acknowledgment of certain power marketing actions as integral to dam operations and system management (given their practical effect, as explained above), and expressing the intent that such actions be subject to the requirements of Section 4(h)(11)(A).

The Environmental Parties’ Brief on Exceptions next argues that BPA’s interpretation of Section 4(h)(11)(A) creates an “odd result” with respect to Section 4(h)(8)(A) of the Northwest Power Act, a principle that applies to the Council in the preparation of its Fish and Wildlife Program. Environmental Parties Br. Ex., BP-22-R-ID-01, at 9. Their argument is this: Section 4(h)(8)(A) contemplates that the Council’s program would include “[e]nhancement measures . . . as a means of achieving offsite protection and mitigation” *Id.* at 8. And because a substantial portion of the Council’s program involves such offsite enhancement as habitat protection and improvements, hatchery production, and the like – which would fall outside the scope of activities subject to Section 4(h)(11)(A) under BPA’s interpretation of the provision – the effect of BPA’s interpretation is an illogical exclusion of enhancement activities from the purview of Section 4(h)(11)(A) despite that provision’s use of the phrase “enhance.” *Id.* at 8-9.

However, the Environmental Parties’ argument here utterly ignores that management and operation of the facilities and the hydro system can and do provide for off-site enhancement away from the projects, particularly with regard to habitat. Indeed, one of the congressional purposes of the Northwest Power Act is “to protect, mitigate, and

enhance fish and wildlife, including related spawning grounds and habitat, . . . particularly anadromous fish . . . which are dependent on suitable environmental conditions *substantially obtainable from the management and operation of the Federal Columbia River Power System and other power generating facilities on the Columbia River and its tributaries.*” 16 U.S.C § 839(6) (emphasis added); *see also* Interior Report at 54 H.R. Rep. No. 96-976, pt. II, at 54 (Sept. 16, 1980) (explaining that the bill becoming the Northwest Power Act would also include critical amendments to the Transmission System Act (codified at 16 U.S.C. § 838(i)(b)(6)), ensuring that BPA could support operations to benefit fish by making short-term power purchases to offset power losses from fish operations: “Section 8(a) amends the Federal Columbia River Transmission System Act to permit BPA to use the BPA Fund to make short term power purchases to enable BPA to meet its obligation under the fish and wildlife provisions of this bill (*e.g.*, to buy power to replace power generating capability that may be lost through a spill for fish passage purposes at a Federal dam.)”).

This reality bears out through system operation and management actions, including those reflected in the CRSO EIS ROD and associated biological opinions, such as the Hanford Reach Fall Chinook Protection Agreement¹² to ensure sufficient flows for redds from the spawning period through emergence and rearing (*see* Biological Assessment of Effects of the Operations and Maintenance of the Federal Columbia River System on ESA-Listed Species, (Jan. 2020, at 2-31, 2-46, A-13) *available at* https://www.salmonrecovery.gov/doc/default-source/FCRPS-BiOp/2020-01-23_crs-final-ba-with-appendices.pdf?sfvrsn=2); cooling water released from Dworshak to benefit downstream fish during summer heat (*see id.* at 2-46); flows to protect chum spawning below Bonneville Dam (*see id.* at 2-46, 2-47) and altering reservoir elevations to enable tributary access or reduce avian predation on salmonids (*see id.* at 2-57, 2-117); etc. Furthermore, in *Confederated Tribes*, the Ninth Circuit cited similar examples, including BPA’s power marketing actions to avoid power emergency operations (that would curtail planned fish operations) and, again, using water from Dworshak for downstream cooling. 342 F.3d at 932. Moreover, some such operations- or management-based enhancement actions are reflected in the Council’s Program. *See generally* Northwest Power and Conservation Council, Mainstem Amendments to the Columbia River Basin Fish and Wildlife Program (2003), *available at* <https://www.nwcouncil.org/fish-and-wildlife/previous-programs/2003-mainstem-amendments-to-the-columbia-river-basin-fish-and-wildlife-program>.

Next the Environmental Parties claim that BPA’s interpretation of Section 4(h)(11)(A)(ii) is “implausible in context.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 10. They argue that because Section 4(h)(11)(A)(ii) includes the duty for BPA to take the Council’s program into account to the fullest extent practical, and because the Council’s program contains extensive non-operational measures for fish and wildlife mitigation (*i.e.*, of the sort that BPA implements through off-site fish and wildlife projects it funds), it is “highly

¹² [https://www.grantpud.org/templates/galaxy/images/images/Downloads/ResourceCommittees/OtherLicenses/Hanford Reach Protection Program Executed Agreement 4-5-04.pdf](https://www.grantpud.org/templates/galaxy/images/images/Downloads/ResourceCommittees/OtherLicenses/Hanford%20Reach%20Protection%20Program%20Executed%20Agreement%204-5-04.pdf)

implausible” that Congress would assign BPA a primary role in implementing the Council program and then “limit[] the influence of the Council program on BPA to a relatively narrow set of decisions that do not implicate a huge swath of the program.” *Id.* at 9-10. This result, the Environmental Parties allege, would “frustrate” the overall statutory scheme. *Id.* That may well be the case, if not for Section 4(h)(10)(A). That provision creates a unique responsibility applicable only to BPA and requires the agency to fund fish and wildlife mitigation “*in a manner consistent with*” the Council’s program. *See* 16 U.S.C. § 839b(h)(A). BPA’s interpretation of the two sections reasonably relies on the guidance in the Council’s entire program for both the funding of fish and wildlife mitigation “in a manner consistent with” the program as well as providing equitable treatment by “taking into account” the program in the management and operation of the dams. BPA’s interpretation does nothing to “frustrate” the statutory scheme, nor does it lead to the “implausible” result the Environmental Parties claim.

Finally, the Environmental Parties propose a construction of the term “managing,” in Section 4(h)(11)(A), as including both BPA’s duty to market power and its duty to fund fish and wildlife mitigation under Section 4(h)(10)(A). *Id.* at 10-11. Because there seems to be no dispute that BPA’s power marketing responsibilities are subject to the equitable treatment provision of Section 4(h)(11)(A) (*see, e.g., Nw. Env’tl. Def. Ctr.*, 117 F.3d at 1533; *see* Environmental Parties Br. Ex., BP-22-R-ID-01, at 10), BPA has only to consider whether its fish and wildlife funding is subject to Section 4(h)(11)(A)’s provisions, as the Environmental Parties claim. Resolution of this question does not require BPA to decide on a definition of the statutory term and it is unnecessary to do so at this time. Instead, in light of the rationale that the Environmental Parties provide, BPA only needs to consider the narrow issue presented in this Issue 4.2.1.

Other than a general observation that “management” is a “broad term,” the Environmental Parties identify two reasons that BPA’s fish and wildlife mitigation should be considered “managing”: (1) funding of fish and wildlife mitigation is clearly within BPA’s power to implement under Section 4(h)(10)(A), and (2) doing so is “integral to the legal, effective functioning of the hydropower system.” *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at 10-11. The first point is too broad to be dispositive, as BPA has numerous ancillary responsibilities that are not subject to the equitable treatment mandate or Section 4(h)(11)(A). *See, e.g.,* 16 U.S.C. § 838b. The second point lacks any supporting analysis or authority. As such, it is a dubious basis for BPA to depart from the interpretation of Section 4(h)(11)(A) it has adhered to for decades and that is supported by the extensive analysis and authority discussed in this section. But more importantly, the Environmental Parties’ second point creates inconsistencies with applicable Ninth Circuit case law that has guided BPA over those years.

The Ninth Circuit says that BPA’s equitable treatment mandate is “independent” of its duty to take the Council’s program into account to the fullest extent practicable. *See Nw. Env’tl. Def. Ctr.*, 117 F.3d at 1532.¹³ The Environmental Parties’ interpretation of “managing”—

¹³ As discussed in further detail below (*infra* Sec. 4.2.3), the court has emphasized the independent nature of the equitable treatment mandate to support the holding that “a federal agency could not satisfy its equitable

contrary to Ninth Circuit jurisprudence—would make BPA’s equitable treatment compliance *dependent* on its duties with respect to the Council’s program, particularly the duty to protect, mitigate, and enhance fish and wildlife in a manner consistent with the Council’s Program under Section 4(h)(10)(A). And if the Section 4(h)(11)(A)(ii) duty to take the Council Program into account is independent of its adjacent statutory mandate under Section 4(h)(11)(A)(i) to provide equitable treatment, it follows all-the-more that BPA’s duty to fund fish and wildlife mitigation, consistent with the Council’s Program, under a separate paragraph of the statute, Section 4(h)(10)(A) (and the funding BPA budgets to implement it), is likewise independent of the equitable treatment provision.

And finally, if “managing” means “funding,” then under the Environmental Parties’ construction of the Northwest Power Act the equitable treatment mandate becomes another standard for reviewing Bonneville’s compliance with Section 4(h)(10)(A). In practice, the subject of the court’s focus when considering equitable treatment has been power marketing and system operation actions, not budgets or funding levels. BPA finds no basis for accepting the Environmental Parties’ interpretation of Section 4(h)(11)(A).

The Environmental Parties also claim that their interpretation of “managing” is appropriate because it gives “independent meaning” to the term, while BPA’s interpretation “essentially construes ‘operating’ and ‘managing’ to mean the same thing,” contrary to established rules of statutory construction. *Environmental Parties Br. Ex., BP-22-R-ID-01*, at 11. This is not so. BPA does not take the position that “operation” and “management” are interchangeable, and indeed does not even attempt to define either of those terms or classify its power marketing responsibilities as one or the other. It would be impractical (and senseless) to do so here; in all likelihood, the practical effect of BPA’s power marketing decisions may well implicate either “operations” or “management,” depending on the nature of each discrete action, or perhaps neither. The Environmental Parties also explain that the term “managing” was not used in pre-Northwest Power Act legislation describing the Corps’ or Reclamation’s responsibilities for the projects (to “operate” and “maintain”) and therefore, Congress’s addition of “managing” must signify an intent to sweep BPA’s fish and wildlife mitigation funding into the meaning of that term. *Id.* at 5-6. However, this choice as easily can be interpreted as an intent to bring BPA’s power marketing actions within the scope of Section 4(h)(11)(A)’s duties, as discussed above.

BPA’s interpretation as to the applicable scope of Section 4(h)(11)(A) remains as initially explained above. Sections 4(h)(10)(A) and 4(h)(11)(A) plainly create two distinct mandates. *See Nw. Env’tl. Def. Ctr.*, 117 F.2d at 1532; *Cutter, BP-22-E-ID-01*, at 3 (acknowledging both BPA’s role in system operations, and also its separate responsibility to fund mitigation of fish and wildlife affected by federal hydropower development and operation under 16 U.S.C. § 839b(h)(10)(A)). The former, by its express plain language,

treatment responsibilities under paragraph (i) simply by adopting the Council’s program under paragraph (ii). *See Nw. Env’tl. Def. Ctr.*, 117 F.3d at 1532. And while the Court later held that reliance on the Council Program for equitable treatment compliance was not improper, it did not hold that doing so was necessary. *See Confederated Tribes*, 342 F.3d at 934 (accepting non-Council program actions as supporting BPA’s compliance with the equitable treatment mandate).

plainly controls the funding and expenditures for the fish and wildlife mitigation projects with which the Environmental Parties are concerned. *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at n.130 (“The Environmental Parties are focused on BPA’s funding of its ‘direct’ fish and wildlife program, the Lower Snake River Compensation Plan, and other non-operational mitigation and enhancement measures and projects.”). The latter, again by its express plain language, concerns management and operation of “hydroelectric facilities.”

To collapse one provision into the other when the two are codified apart¹⁴ and use distinct language¹⁵ relating to different methods of fish and wildlife protection, would require an assumption “that Congress chose a surprisingly indirect route to convey” the intent espoused by the Environmental Parties. *See Landgraf v. USI Film Products*, 511 U.S. 244, 262 (1994); *see also Am. Tobacco Co. v. Patterson*, 456 U.S. 63, 75 (1982) (“Going behind the plain language of a statute in search of a possibly contrary congressional intent is a step to be taken cautiously even under the best of circumstances.”) (internal quotation omitted). BPA doubts that is the case here. Had it intended to, Congress could have effected that end, by much simpler means: either by (1) importing equitable treatment language into Section 4(h)(10)(A) and thus clearly applying the requirement of fish and wildlife funding, or (2) including language concerning funding or expenditures for fish and wildlife mitigation in Section 4(h)(11)(A), with the same result. Congress did neither here.

This leads to BPA’s final point: in disputing BPA’s interpretation as to the applicability of Section 4(h)(11)(A), the Environmental Parties’ Brief on Exceptions builds an argument around supposed “implausible” results and legislative drafting alternatives. Environmental Parties Br. Ex., BP-22-R-ID-01, at 10. But in their attempt to avoid a result they dislike, they reject the simplest reading of the statute and ultimately fail to reckon with its plain text or the applicable Ninth Circuit case law that BPA discusses above. In sum, BPA is not persuaded by the arguments the Environmental Parties have raised, and has addressed those arguments in detail over the preceding pages. Therefore, BPA finds no basis to depart from its initial interpretation as to the non-applicability of Section 4(h)(11)(A)’s equitable treatment mandate to fish and wildlife mitigation expenditures.

That is not to say that there is *no* context in which BPA considers equitable treatment. The CRSO EIS and associated ROD show BPA’s consideration of and compliance with equitable

¹⁴ The Environmental Parties cite *United States v. Morton*, 467 U.S. 822 (1984) and *Westwood Apex v. Contreras*, 644 F.3d 799 (9th Cir. 2011) for the proposition that statutory provisions must be analyzed in context. BPA agrees that context is critical, but notes that those cases dealt with the meaning of disputed statutory terms where their ambiguity was resolved by examining immediately adjacent language in the same sentence of the statute. Here, the Environmental Parties essentially package as a “context” argument their contention that one paragraph of the Northwest Power Act includes another, despite the lack of a direct textual connection between the two.

¹⁵ *See Ariz. Health Care Cost Containment Sys. v. McClellan*, 508 F.3d 1243, 1250 (9th Cir. 2007) (“[A] court must presume that Congress intended a different meaning when it uses different words in connection with the same subject . . .”).

treatment in selecting system operations and management actions for power marketing.¹⁶ Thus, BPA did not ignore its duty to consider equitable treatment in its system operations and power marketing decisions. Nonetheless, the decision made in the CRSO EIS ROD is currently being challenged in multiple judicial forums (*e.g.*, U.S. District Court for the District of Oregon and the U.S. Court of Appeals for the Ninth Circuit), including by some of the Environmental Parties, and equitable treatment claims have been raised in those challenges.¹⁷ There is, therefore, no compelling reason to raise those challenges again here because this is not the appropriate forum, and those challenges will be decided by the appropriate proceedings.

Decision

The “equitable treatment” provision of the Northwest Power Act Section 4(h)(11)(A)(i) applies to BPA’s system operation and management actions, but does not apply to its fish and wildlife mitigation planning budgets or spending.

Issue 4.2.2

Whether a final rate determination, including adoption of a proposed settlement, significantly affects fish and wildlife such that BPA must demonstrate that a final rate determination provides for equitable treatment of fish and wildlife under the Northwest Power Act.

Parties’ Positions

The Environmental Parties argue that “BPA’s final rate determination in this rate case qualifies as a ‘final decision that significantly impacts fish and wildlife,’ requiring the agency to ‘demonstrate compliance with the equitable treatment mandate’ at this time.” Environmental Parties Br., BP-22-B-ID-01, at 13. They contend that BPA’s rate determination implements BPA’s “intermediate or preliminary” decisions from the Integrated Program Review (IPR) and the Strategic Plan, and that “together” these decisions “trigger[] BPA’s obligation to demonstrate compliance with the equitable

¹⁶ Several examples demonstrating BPA’s consideration and fulfillment of its equitable treatment responsibility in the context of the CRSO EIS include, but are not limited to, the following: (1) the purpose and need statement for the EIS, *see* CRSO FEIS § 1.2 (“Comply with environmental laws . . . including those specifically addressing the CRS such as requirements under the Northwest Power Act ‘to adequately protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by such projects or facilities in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated.’”); (2) *Id.* § 2.4.2.1 at 2-33 (discussing decades of overhauls to system operations, management, and configuration, including the results of such actions, as providing equitable treatment for fish); (3) *Id.* § 5.2.1 (“[T]he entire CRSO EIS process is an exercise in providing equitable treatment on a system-wide basis by using alternatives and analysis that balance the various system purposes, including fish and wildlife, power, navigation, flood risk management, and the other authorized purposes of the CRS”); (4) *See generally* CRSO FEIS, Appendix T; and (5) CRSO EIS ROD § 5.5.1 (summarizing adherence to equitable treatment).

¹⁷ Idaho Rivers joined *Nat’l Wildlife Fed’n v. Nat’l Marine Fish. Serv.*, 01-640-SI (D. Or.), in the U.S. District Court for the District of Oregon, where BPA is not a party. Idaho Rivers and Idaho Conservation League joined *American Rivers v. Bonneville Power Admin.* (Nos. 20-73761, 20-78762, 20-73775) in the U.S. Court of Appeals for the Ninth Circuit.

treatment mandate. *Id.* at 16; *see also* Environmental Parties Br. Ex., BP-22-R-ID-01, at 12-21.

BPA Staff's Position

Whether the “equitable treatment” in Section 4(h)(11)(A)(i) of the Northwest Power Act applies to BPA’s ratemaking decisions is a legal issue. *See* Mandell *et al.*, BP-22-E-BPA-46, at 2. Nevertheless, as Staff explained in that testimony, BPA’s power rates are set to recover the costs of BPA’s environmental obligations, including the costs of fish and wildlife mitigation and operational measures developed in agency decision documents that direct system operations and management, such as the CRSO EIS and associated Endangered Species Act (ESA) consultations. *Id.* Whether these costs or operations are sufficient to meet BPA’s environmental obligations – including equitable treatment – “are determined in other forums . . .” *Id.*

Evaluation of Positions

In asserting that BPA must demonstrate equitable treatment of fish and wildlife at the time of a final rate determination, the Environmental Parties cite *Confederated Tribes* for the proposition that BPA’s “duty to demonstrate compliance with the [equitable treatment] mandate matures only when BPA makes a final decision that significantly impacts fish and wildlife.” Environmental Parties Br., BP-22-B-ID-01, at 17 (citing *Confederated Tribes*, 342 F.3d at 931), 20. Here, the significant impact on fish and wildlife alleged by the Environmental Parties relates to the level of funding available for expenditure on fish and wildlife mitigation actions. *See, e.g., id.* at 15-16, 22 (proposing that a “boost” in fish and wildlife funding is needed to satisfy equitable treatment); *id.* at 18-19 (focusing on alleged potential impact of *funding levels* on fish and wildlife as trigger for equitable treatment in a final rate determination); *id.* at 20 (linking projected spending for fish and wildlife mitigation with the equitable treatment mandate).

The Environmental Parties’ focus on fish and wildlife funding levels, in their contention that a final rate determination creates an obligation to demonstrate equitable treatment, incorporates the same foundational legal flaw explained in Issue 4.2.1, above – that is, the mistaken assumption that equitable treatment applies to programmatic fish and wildlife mitigation spending. Thus, as an initial matter, the Environmental Parties’ reliance on this flawed premise is fatal to their assertion that equitable treatment must be demonstrated in a final rate determination because the mandate simply does not apply to funding. (In a variation on their primary position, the Environmental Parties also assert that “intermediate” or “preliminary” “decisions” relating to fish and wildlife spending levels stemming from IPR or BPA’s Strategic Plan, “taken together” with a final rate determination, have a significant impact on fish and wildlife and therefore trigger an obligation to demonstrate equitable treatment in BPA’s rate case. *Id.* at 16-17. This assertion fails for its reliance on the same mistaken assumption noted above. (There are additional problems with the Environmental Parties’ arguments as to the reviewability of IPR and the Strategic Plan, which BPA explains and addresses separately in Issue 4.2.4.)

Furthermore, a final rate determination does not satisfy the Ninth Circuit’s test for when the duty to demonstrate equitable treatment arises because BPA’s ratemaking decisions

have no significant impact on fish and wildlife. *See Confederated Tribes*, 342 F.3d at 931 (“duty to demonstrate compliance with the [equitable treatment] mandate matures only when BPA makes a final decision that significantly impacts fish and wildlife.”). A basic understanding of the nature and context of BPA’s ratemaking function illustrates this point.

BPA ratemaking is designed to do one thing: recover costs. The reason for this narrow function of ratemaking is not “arcanelly compartmentalized procedures” as alleged by the Environmental Parties, *Environmental Parties Br.*, BP-22-B-ID-01, at 2, but instead is based in logical statutory construction. Section 7(a)(1) of the Northwest Power Act establishes BPA’s foundational statutory obligation to set its rates to recover its costs:

The Administrator shall 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. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (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 pursuant to this chapter and other provisions of law. Such rates shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. 838) [16 U.S.C. 838g and 838h], section 5 of the Flood Control Act of 1944 [16 U.S.C. 825s], and the provisions of this chapter.

16 U.S.C. § 839e(a)(1).

The statute plainly shows BPA’s cost recovery obligation encompasses costs directly related to power production (acquisition, conservation, and transmission of electric power, and the amortization of the Federal investment) as well as the Administrator’s other “costs and expenses” imposed “pursuant to this chapter and other provisions of law,” including expenditures for fish and wildlife mitigation. Section 7(a)(2) provides additional factors the Federal Energy Regulatory Commission (FERC) is to review in affirming BPA’s rates – and (as discussed further below) the provision of equitable treatment is not among them. Importantly, nothing in Section 7(a)(1) or (a)(2) suggests that BPA must decide how it will meet its other legal obligations when establishing its rates. To the contrary, Section 7(a)(1) presumes the costs flowing into rates reflect those obligations, thus leaving the focus of ratemaking to “establishing” rates to “recover” those costs “in accordance with sound business principles.” This sequencing of events makes sense because BPA cannot make the statutory showings required by Section 7(a)(1) and 7(a)(2) unless and until it has already projected its costs. *See Golden Nw. Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1052–53 (9th Cir. 2007) (explaining that BPA’s recovery of costs through rates requires that BPA first develop a realistic projection of its costs) (*Golden NW*).

The context of these Northwest Power Act provisions, governing FERC’s review of BPA’s rates, further demonstrates that BPA rate determinations do not implicate the equitable treatment mandate. If BPA’s final rate decisions trigger BPA’s obligation to consider

equitable treatment, as asserted by the Environmental Parties (*see* Environmental Parties Br., BP-22-B-ID-01, at 16–20), it follows that FERC would also have to consider equitable treatment when making its findings on BPA’s rates under Northwest Power Act Section 7(a)(2), 16 U.S.C. § 839e(a)(2). But nothing in the Northwest Power Act, its legislative history, or indeed, 40 years of implementation suggests that FERC should consider equitable treatment in approving BPA’s rates. More importantly, such an outcome would, without a statutory basis, expand Congress’s narrow prescription for FERC’s review of BPA’s rates in Section 7(a) of the Northwest Power Act, *see* 16 U.S.C. § 839e(a)(1)-(2), wherein Congress made no mention of equitable treatment as within FERC’s authority to review. *See also Cent. Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984) (“In light of the far more detailed rate directives to BPA that the Act contains, the congressional intent to avoid rate-making delay is served only if the substantive scope of FERC review has been limited.”). The legislative history of the Northwest Power Act helps confirm Congress’s intent with respect to FERC’s role as it relates to equitable treatment in Section 4(h)(11)(i)(A). As it applies to FERC, “equitable treatment” was intended to be *supplemental* to FERC’s existing obligations to consider fish and wildlife in the context of its regulatory function in reviewing non-federal hydropower licensing under Section 10 of the Federal Power Act: “This provision does not replace other provisions of law such as FERC’s Section 10 of the Federal Power Act, but supplements it.” H. Rep. No. 97-976, pt. 1 at 57 (1980). There is, unsurprisingly, no mention anywhere in the Northwest Power Act or its legislative history of equitable treatment being a component of FERC’s other review authorities, such as its review of BPA’s rates.

In short, ratemaking establishes *how* BPA will recover its forecasted costs through rate allocations, rate design, and rate levels; ratemaking does not determine *whether* to incur a cost, or *which* costs to incur. *See Golden NW*, 501 F.3d at 1053 (acknowledging that BPA’s “rate case was not the forum for making decisions regarding which fish and wildlife alternative to implement”). All programmatic cost obligations – whether they be BPA staffing costs, energy efficiency costs, capital project costs, or funding for fish and wildlife mitigation expenditures – flow from inputs arising outside of the rate case. The point of the rate-setting process is not to question or second-guess these assumptions, but to recover these costs through rates set in accordance with “sound business principles.”¹⁸ *See* 16 U.S.C. § 839e(a)(1). Therefore, in the context of programmatic costs, BPA’s ratemaking decisions do not disrupt or opine on the underlying programs or actions. And while the general projection of these costs are incorporated into BPA’s rates, neither the projections themselves nor BPA’s rate case process in any way controls or determines what BPA’s *actual* costs will be throughout the rate period. Similarly, and crucially here, a final rate determination does not in any way plan or select for system operations and management actions, or alter such actions once they have been planned through other processes, *see*

¹⁸ BPA is aware of *Golden NW*’s implication that changed circumstances or new evidence could make reconsideration of BPA’s cost assumptions appropriate in certain instances. *See Golden NW*, 501 F.3d at 1051. However, as explained in Issue 4.2.3, BPA finds no such circumstances or evidence in the current rate proceedings.

Mandell *et al.*, BP-22-E-BPA-46, at 4; it merely sets rates to recover the projected costs of such actions.

The preceding overview of BPA's ratemaking function shows that, while the actions or programs forming the basis for BPA's projected costs might have an effect on fish and wildlife, the mere *recovery* of such costs through a final rate determination does not. But the Environmental Parties misconstrue the essential nature of ratemaking, conflating recovery of costs with implementation of actions. A final ratemaking determination does not, as the Environmental Parties suggest, "implement[]" the programs or actions that make up the costs underlying BPA's rates. Environmental Parties Br., BP-22-B-ID-01, at 18; *see also id.* at 19 (claiming that a BPA rate decision "puts into effect" earlier funding "decisions"). A decision to recover costs does not, indeed *could not*, implement actions or expenditures (whether for fish and wildlife or other programmatic initiatives) that invariably require further planning, studies, contracting, permitting, partnership coordination, environmental compliance work, subsequent decisions or a host of other factors to actually execute.

Because BPA does not decide which fish and wildlife mitigation actions to fund in the ratemaking process, and because a final rate determination neither implements such actions nor prescribes system operations and management, a rate determination is not an action that "significantly impacts fish and wildlife." The Environmental Parties, therefore, are forced to fall back on speculation, asserting that BPA's rate decisions *might* significantly affect fish and wildlife. "[I]f the rates . . . are too low, BPA runs the risk of not recovering its true costs, putting at risk its ability to meet its legal obligations to fish and wildlife." Environmental Parties Br., BP-22-B-ID-01, at 18. This speculative concern, however, suffers from a number of critical flaws.

First, the threshold trigger for equitable treatment to apply requires more than the *possibility* of an impact on fish and wildlife. As *Confederated Tribes* shows, the mandate matures with a final decision that actually impacts fish and wildlife – not the mere *possibility* of an impact. *See Confederated Tribes*, 342 F.3d at 931 ("the mandate matures only when BPA makes a final decision that significantly *impacts* fish and wildlife") (emphasis added). *Nw. Env'tl Def. Ctr.* illustrates this principle. In that case, the court declined to review whether BPA met its equitable treatment responsibilities regarding the allocation of water between fish and power purposes before BPA allocated it: "The court's role is not to dictate in advance how BPA is to exercise its obligations under the Northwest Power Act. Our role is to review BPA's *actions, once made*, to determine whether it has provided equitable treatment." 117 F.3d at 1533 (emphasis added). In other words, the possibility that BPA *might* allocate more water to power, which *might* in turn impact fish, was inadequate to support an equitable treatment challenge. In addition, the court's opinion in *Nw. Env'tl. Def. Ctr.* examined the fish and wildlife impacts alleged to trigger BPA's duty to demonstrate equitable treatment and found it important that "BPA's environmental assessment shows, and petitioners do not present evidence to the contrary, that the [non-treaty storage agreements being challenged] will not significantly impact the fish *population* of the river . . ." *Id.* at 1534 (emphasis added). Environmental Parties here

fail to present evidence that BPA's adoption of a final rate decision will affect any fish populations.

To be sure, during their participation in the BP-22 rate case, the Environmental Parties have generally asserted an overall decline or imperiled status of certain Snake River salmon and steelhead species, *see* Environmental Parties Br., BP-22-B-ID-01, at 2, n.8, but they fail to present evidence connecting that decline to the pending rate determination or the settlement to which they object. In fact, they do not make that claim. At most, they offer conclusory speculation that *if* rates are set too low, BPA puts at risk its ability to meet its legal obligations to fish and wildlife. *Id.* at 18. But they fail to offer evidence that this will actually be the case, or that BPA's rate mitigation provisions will be inadequate to recover BPA's costs. *See* Issue 4.2.3 (discussing the various, vague assertions as to the adequacy of BPA's fish and wildlife budgets and projected costs that the Environmental Parties have proffered in the course of this rate case and other recent processes).

Second, simply because BPA does not forecast a new or different cost, or a cost projection turns out not to be accurate, does not mean BPA *cannot* pay for that cost if it is legally due. BPA's spending for its actual obligations is not ultimately constrained by its rate case cost estimates. The Environmental Parties observe that "funding levels, once determined during IPR and factored into the revenue requirement underlying BPA's rates, are substantially adhered to." Environmental Parties Br., BP-22-B-ID-01, at 19. While this observation may be generally accurate as a matter of practice, nothing prevents BPA from deviating from its cost estimates or projected spending levels to ensure that its actual obligations, for fish and wildlife or otherwise, are met during a rate period.¹⁹ In practice, as new obligations or unexpected circumstances arise, or as old programs are phased out, BPA's costs and spending levels will fluctuate naturally in response. And if BPA had incorrectly estimated the cost of an obligation, BPA would nonetheless comply with such obligation and take any number of actions to ensure that it could cover the financial cost of doing so, including cost-saving actions such as reducing or reprioritizing discretionary spending, or relying on its risk mitigation measures (Cost Recovery Adjustment Clauses (CRACs), Financial Reserves Policy Surcharge, repurposing revenue financing, etc.).

Third, there is no evidence in this rate proceeding to suggest BPA will be in a position that runs the risk of under-recovering its costs because of its fish and wildlife projections. BPA has met the requirement of a "realistic projection" of costs based on information "available at the time rates were set." *See Golden NW*, 501 F.3d at 1053. BPA has already conducted *two* processes to assess the sufficiency of its fish and wildlife spending. The first IPR

¹⁹ The Environmental Parties' initial brief cites BPA's 2020 Annual Report, which states that "BPA's IPR cost expenditures for the year are \$1.7 billion, which is 97% of the rate case expectation," to support their contention that IPR funding levels are substantially adhered to – in effect, a spending cap. *Id.* at n.99. However, the Environmental Parties did not consider a simple alternative: that IPR's projected expenditures turned out to be fairly close to what was required. In addition, BPA's expenditures came within 97% of rate case expectation in the *aggregate*; there were individual cost categories that were both above and below rate case expectations. *See* Q4 Quarterly Business Review Technical Workshop, at 4, 6 (November 19, 2020) available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/qbrdocs/FY20%20QBR%20Tech%20Workshop%20presentation%201.25.pdf>.

process (IPR 1) concluded at the end of September 2020, leading to the fish and wildlife spending levels used in the Initial Proposal for setting BPA's power rates. A few days before issuance of the IPR 1 Closeout Report, BPA and other agencies issued the CRSO EIS ROD, which included actions BPA agreed to fund to benefit fish and wildlife affected by CRS operations. *See* CRSO EIS ROD, Attachment 1 (Mitigation Action Plan).²⁰ The CRSO EIS evaluated the costs of these actions. *See* CRSO FEIS §§ 3.19, 7.7.21 & Appendix Q. BPA held a second IPR process (IPR 2) to consider, among other matters, whether revisions to the projected costs of its fish and wildlife obligations were needed. *See* Mandell *et al.*, BP-22-E-BPA-46, at 3; *see also* IPR 2 Letter to the Region, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2020.aspx>. In the IPR 2 Closeout Report issued in April 2021 – three months before the publication of this BP-22 Final ROD – BPA confirmed that it found no reason projections in IPR 1 would not be sufficient to meet the agency's various environmental obligations over the BP-22 rate period. *See* IPR 2 Closeout Report at 4, 8-11, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2020.aspx>. Thus, BPA's fish and wildlife funding is based on a realistic projection using the best available information from IPR 1 and informed by the CRSO EIS ROD. And there is no evidence in the record of this case to contradict that BPA's cost estimates are based on the best available data. *See* Issue 4.2.3 (considering and addressing the Environmental Parties' various assertions as to the need for higher fish and wildlife cost estimates in BPA's projections).

Fourth, even if BPA's projections were in error, BPA has additional measures built into its rates to ensure BPA's costs are recovered. As described in BPA Staff's rebuttal testimony, BPA has six lines of risk mitigation to ensure its costs are recovered in the event of a new or different fish and wildlife cost obligation, including (1) financial reserves; (2) Financial Reserve Policy (FRP) Surcharge; (3) Cost Recovery Adjustment Clause (CRAC); (4) the \$40 million in revenue financing (which could be repurposed to ensure BPA's financial reserves are not depleted); (5) access to a \$750 million U.S. Treasury Note; and (6) the commencement of a new Section 7(i) process to revise rates as needed. Mandell *et al.*, BP-22-E-BPA-46, at 9-10. These risk mitigation measures, coupled with BPA's use of the most recent data on its fish and wildlife projections, leave no room for the Environmental Parties' assertion that BPA's current rates significantly impact fish and wildlife because they "run[] the risk of not recovering its true costs, putting at risk its ability to meet its legal obligation to fish and wildlife." *See* Environmental Parties Br., BP-22-B-ID-01, at 18.

In its Brief on Exceptions, the Environmental Parties contend that BPA's description of its ratemaking process, and its emphasis on the process' cost recovery purpose, is "beside the point" with respect to whether a final rate determination must demonstrate equitable treatment. Environmental Parties Br. Ex., BP-22-R-ID-01, at 13. Instead, the Environmental Parties argue that the "string of decisions culminating in this rate case

²⁰ The Mitigation Action Plan identifies the actions BPA committed to fund as part of the CRSO EIS and associated ESA consultations. This includes actions such as funding the USFWS with annual operations and maintenance funding for the Lower Snake River Compensation Plan (LSRCP) in accordance with BPA's direct funding agreement with USFWS and any future renewals, as well as other hatchery, habitat, and research, monitoring and evaluation actions.

includes decisions about how much to spend on fish and wildlife mitigation and enhancement measures, and that the set of decisions must be viewed as a unified whole when assessing whether the ‘final decision’ at issue – the rate determination – has a substantial effect on fish and wildlife.” *Id.* at 14.

BPA disagrees. As noted above, BPA’s obligation to demonstrate its compliance with the equitable treatment mandate arises “when BPA makes a final decision that significantly impacts fish and wildlife.” *Confederated Tribes*, 342 F.3d at 931. Thus, the questions BPA must consider to determine whether equitable treatment is implicated in the final rate determination are (1) *what* final decisions is BPA making as part of its final rate determinations; and (2) whether *those* decisions “significantly impact fish and wildlife.”

The final decision that BPA is making in this proceeding is limited to the level of its power and transmission rates. *See, e.g.*, Fiscal Year (FY) 2022-2023 Proposed Power and Transmission Rate Adjustments[,], Public Hearing and Opportunities for Public Review and Comment,” 85 Fed. Reg. 77,189 (Dec. 1, 2020) (“[BPA] is initiating a rate proceeding under the Northwest Power Planning and Conservation Act (Northwest Power Act) to establish power, transmission, and ancillary and control area services rates for the period from October 1, 2021, through September 30, 2023.”). Supporting that decision is, of course, data inputs from a variety of sources, including funding projections for planned fish and wildlife budgets, and those projections are informed by other agency policies or objectives. But at the end of the day, the only “decision” that is being made in the final rate determination related to BPA’s fish and wildlife funding is that rates are set on “realistic” projections of those obligations and that those obligations are based on information “available at the time the rates were set,” *see Golden NW*, 501 F.3d at 1053, and supported by substantial evidence. *Id.* at 1051; 16 U.S.C. § 839f(e)(2). As discussed extensively above, they are. Setting rates to recover costs in the final rate determination is, thus, not “beside the point” – it is the whole point of the final rate determination. And, importantly, setting rates to recover those projected costs does not “significantly impact fish and wildlife” because all BPA is doing in ratemaking is figuring out how to pay for what it expects to spend – not determining what ultimately to spend.

The Environmental Parties, nevertheless, contend more is being decided here with regards to BPA’s fish and wildlife projections. Pointing to the Administrative Procedure Act and case law, the Environmental Parties characterize the Strategic Plan, which provided general policy direction in the IPR projections for all of BPA’s program areas, as “preliminary, procedural, or intermediate agency actions or rulings not directly reviewable [but] subject to review on the review of the final agency action.” *Environmental Parties Br. Ex., BP-22-R-ID-01*, at 14. In other words, BPA’s final rate determination is doing more than just setting rates and recovering costs. It is implementing policies that limit, in the Environmental Parties’ view, BPA’s fish and wildlife funding. Once the Strategic Plan and IPR decisions are taken into account, they contend, the impact of the final rate determination is much broader, and results in a “significant impact” on fish and wildlife that implicate “equitable treatment.”

Several problems arise from the Environmental Parties' multi-level, culminating impact theory. First, the Environmental Parties' argument presumes that the Strategic Plan and IPR projections become reviewable within the final rate determination. As explained below in Issue 4.2.4, they do not.

Second, even if the Strategic Plan and IPR were in some way "reviewable" within the final rate determination, that still leaves the question of whether this "string of decisions" has a "significant impact" on fish and wildlife. The crucial "decision" that the Environmental Parties contend is being implemented through the final rate determination is BPA's goal in the Strategic Plan to "manage fish and wildlife program costs at or below inflation, inclusive of new obligations and commitments." Strategic Plan at 39; Environmental Parties Br. Ex., BP-22-R-ID-01, at 18. But even with the application of this goal to the projections in this case, the Environmental Parties have failed to show that the final rate determination "significantly affect" fish and wildlife. To the contrary, BPA has already shown that its rates will recover its projected fish and wildlife costs *even if* its Strategic Plan goals are implemented. In other words, the record in this case shows BPA can do both: it can recover all of its currently known fish and wildlife mitigation costs (consistent with substantial evidence) *and* maintain its fish and wildlife funding at or below the rate of inflation. In doing so, BPA is not shirking its obligations, but balancing objectives. As an agency tasked with operating in accordance with sound business principles, BPA's cost-control objectives related to all programmatic spending do not equate to giving short shrift to fish and wildlife mitigation and enhancement responsibilities. Rather, maintaining financial health enables the agency to repay the Federal investment with cost-competitive rates while enabling BPA to provide funding for extensive programs for fish, wildlife, habitat mitigation and restoration programs based on decisions developed with broad and frequent public involvement.

The Environmental Parties' brief does not outright dispute BPA's current funding levels as insufficient *per se*. Rather, they rely on an unbounded premise that availability of additional funding would ensure additional benefits for fish and wildlife, and thus by constraining fish and wildlife funding to an inflation budget level, BPA must have a "significant effect" on fish and wildlife. Environmental Parties Br. Ex., BP-22-R-ID-01, at 15. As support, the Environmental Parties point to materials from other forums that they contend show needs for additional fish and wildlife funding. *Id.* at 15-16. These requests, according to the Environmental Parties, are merely the "tip of the iceberg," as they cite even more requests for funding. *Id.* at 16-17. The Environmental Parties assert there can be "no serious dispute that BPA's decision to keep fish and wildlife funding flat during BP-22 will have a 'significant impact' on fish and wildlife." *Id.* at 17.

The Environmental Parties' reference to other funding needs is also flawed in that they implicitly attribute each of the funding requests as solely BPA's responsibility. That is incorrect. To the extent these funding obligations arise within a current mitigation funding mandate that is BPA's direct responsibility, those obligations have been included in the proposed budget and rates. BPA is prepared to meet the costs of those obligations, as described earlier, through its current projections. The Environmental Parties' assertion that there are additional needs for fish and wildlife does not establish that BPA is legally

responsible for meeting those needs. Indeed, before claiming BPA must pay more, the Environmental Parties must show how the obligations they discuss are attributable to BPA's funding obligations. They have not done this.

The Environmental Parties' argument also leads to a nonsensical result. In essence, following the Environmental Parties' contention that "more money always equals greater benefits to fish," every funding projection BPA makes with regard to fish and wildlife will trigger "equitable treatment." So long as BPA projects a limit to its fish and wildlife funding, there will always be additional examples of projects that BPA could fund. The Environmental Parties' argument would result in a constant increase in fish and wildlife budgets, because there will always be some stakeholder in some forum requesting additional funds. There is absolutely no support in the Northwest Power Act or its legislative history that Congress intended to impose on BPA such an unbounded funding obligation – or that such funding demands be addressed as a matter of "equitable treatment" in the final rate determination.

The Environmental Parties take their position one step further and assert that "any final rate determination has a 'significant effect' on fish and wildlife, because funding levels for fish and wildlife mitigation efforts obviously have a significant effect on fish and wildlife." Environmental Parties Br. Ex., BP-22-R-ID-01, at 15. To accept this interpretation is to revise congressionally created ratemaking criteria. That BPA cannot do. As described above, BPA's Northwest Power Act Section 7 rate proceedings along with the several substantive, congressionally defined ratesetting and cost allocation requirements included in Section 7 are what governs this proceeding. There is no basis for BPA to add an entirely new evaluation standard unstated in Section 7, one that BPA, FERC, and the courts have allegedly missed for the better part of 40 years.

The Environmental Parties' brief even appears to admit that, by themselves, BPA's rate determinations have no significant effects on fish and wildlife: "[o]nce the scope of analysis is broadened to include earlier non-final actions, it seems clear that any final rate determination has a 'significant effect' on fish and wildlife, because funding levels for fish and wildlife mitigation efforts obviously have a significant effect on fish and wildlife." *Id.* at 15 (emphasis omitted). That is to say, the Environmental Parties have conceded that the final rate determination does not have significant impacts on fish and wildlife unless the scope of BPA's decision is broadened to include the underlying policy goals and agency-level statements from other forums. But even including these other policy goals and statements, there is no need to conduct the "equitable treatment" review. In the end, all BPA is doing here is recovering its known costs through its rates which, as described above, BPA has done.

Finally, the Environmental Parties contend that, even if an "ordinary rate case" does not require demonstration of compliance with equitable treatment, this rate case does because of the large impact the projected secondary revenue *could* have if BPA elected to increase fish and wildlife funding. *Id.* at 21. BPA will address the main parts of the Environmental Parties' argument in Issue 4.2.3. Here, however, BPA notes that by allocating secondary revenue in a manner that benefits power rates BPA is not choosing power benefits over fish

and wildlife. BPA is simply following its ratemaking directives. Section 7(g) of the Northwest Power Act directs that BPA must “equitably allocate to power rates . . . all cost and benefits not otherwise allocated under this section, including. . . the sale of or inability to sell excess electric power.” 16 U.S.C. § 839e(g). In other words, Congress knew there would be both booms and busts with BPA’s sales of secondary power. The benefits and burdens of those forecasts were directed to be allocated to power rates, which BPA has done here. In the face of this plain direction, BPA cannot agree with the Environmental Parties’ view that Congress hid inside the Northwest Power Act an inchoate allocation of secondary revenue to fish and wildlife funding that springs to life through “equitable treatment” only when BPA’s secondary revenues significantly increase.

As a general matter, BPA finds it sensible to demonstrate its adherence to the equitable treatment requirement in the context of decisions in which the mandate squarely arises – that is, decisions involving system operations and management actions with a significant effect on fish and wildlife. For example, the CRSO EIS and associated ROD, whose associated costs over the BP-22 rate period serve as cost inputs in the BP-22 rate case, documents BPA’s consideration of and compliance with the equitable treatment mandate.²¹ Indeed, BPA provided extensive analysis and description of how the CRSO EIS selected alternative provides equitable treatment. Nothing in the BP-22 rate case or proposed settlement changes the actions BPA agreed to fund in the CRSO EIS ROD; to the contrary, the rate case simply sets rates to allow recovery of those costs. And, as described earlier, the Environmental Parties are well aware that the CRSO EIS ROD is a logical context for demonstrating equitable treatment compliance, given that two of the Environmental Parties are party to current legal challenges to this decision in U.S. District Court for the District of Oregon and in the U.S. Court of Appeals for the Ninth Circuit, where their co-plaintiffs or co-petitioners raise specific equitable treatment claims.²²

Decision

BPA’s final rate determination does not significantly affect fish and wildlife such that BPA must demonstrate equitable treatment of fish and wildlife under the Northwest Power Act.

Issue 4.2.3

Whether a projected increase in net secondary revenue constitutes a changed circumstance that would require BPA to reconsider its fish and wildlife funding levels in order to satisfy its Northwest Power Act obligations to fish and wildlife.

Parties’ Positions

The Environmental Parties argue that a forecasted increase in net secondary revenue constitutes a changed circumstance that obliges BPA to reassess its statutory responsibilities for fish and wildlife, specifically the equitable treatment obligation and the requirement to take into account the Northwest Power and Conservation Council’s

²¹ See *supra* note 16.

²² See *supra* note 17.

(Council's) fish and wildlife program. Environmental Parties Br., BP-22-B-ID-01, at 12-15; Environmental Parties Br. Ex., BP-22-R-ID-01, at 21-29.

BPA Staff's Position

In the ratemaking process, BPA Staff assumes that fish and wildlife budgets are developed to be sufficient to fund activities that meet BPA's statutory requirements. Mandell *et al.*, BP-22-E-BPA-46, at 5. The IPR process examines and establishes BPA's fish and wildlife projected spending levels to provide appropriate funding for mitigation activities for the rate period. *Id.* When BPA was developing rate case proposals in light of the new estimates for its surplus sales (*i.e.*, net secondary sales or net secondary revenue), the spending levels for fish and wildlife were already projected to be sufficient to meet BPA's obligations in the IPR process. *Id.* The fact that estimates of net secondary sales came in above anticipated levels did not change the assumption that the funding levels for fish and wildlife were sufficient. *Id.* Additionally, in the event of significant increases in fish and wildlife costs, BPA has risk mechanisms and other tools in place to protect against financial harm in the event of unforeseen cost increases. *Id.* at 9-10. These include financial reserves, the FRP Surcharge, CRACs, debt-financing options, and the option to institute Section 7(i) proceedings to develop rates. *Id.*

Evaluation of Positions

The Environmental Parties contend that, even if BPA's estimates of fish and wildlife funding had met its statutory obligations, those estimates are no longer valid in light of the new increase in net secondary revenues projected to occur during the BP-22 rate period. Environmental Parties Br., BP-22-B-ID-01, at 3, 9, 12-14, 20. Leaning heavily on *Golden NW*, the Environmental Parties assert that this projected increase constitutes a momentous changed circumstance or new information that would require BPA to reconsider its fish and wildlife funding levels for purposes of providing equitable treatment and taking into account the Council's Fish and Wildlife Program. *Id.* at 11-12, 14, 18. The relevant facts at hand are readily and meaningfully distinguishable from those in *Golden NW*, and the new information or changed circumstance that Environmental Parties refer to here present no analogous consequences or bases for reconsideration of BPA's fish and wildlife costs as were present in *Golden NW*.

First, BPA notes that the *Golden NW* court decision did not reach the merits of the equitable treatment challenge in that case. *See* 501 F.3d at 1053. Instead, the court considered whether BPA's fish and wildlife cost projections were supported by substantial evidence in light of evidence presented during the rate proceedings suggesting that such costs were outdated. *Id.* at 1049-53. In deciding the cost projections were not supported by substantial evidence, the court reasoned that the problem lay with BPA's reliance on cost estimates that were several years old and an assumption that each of 13 different fish and wildlife funding alternatives was equally likely to be implemented. *Id.* at 1051. The court faulted BPA for not updating its fish and wildlife costs because of new obligations that had accrued since BPA performed its original estimation of its costs. *Id.* at 1052 (noting that "[b]y the time of the supplemental WP-02 proceeding in late 2000 and early 2001, . . . [a]t least three new developments underscored the need for new cost projections."). The key

issue in *Golden NW*, then, was not *what* BPA's fish costs should be, but *whether* BPA's projection of those costs was based on sound evidence for rate-setting purposes.

Importantly, the plaintiffs in *Golden NW* provided *evidence* to support their assertion that BPA's fish and wildlife cost were unrealistically low. For example, the court found the following evidence persuasive: (1) a "Staff Report" prepared by the Environmental Protection Agency (EPA), U.S. Fish and Wildlife Service (USFWS), and the National Marine Fisheries Service (NMFS) including calculations of "refined cost estimates"; (2) tribal fish and wildlife manager testimony that the cost of BPA's ESA requirements would cause BPA's ability to repay the U.S. Treasury to fall below an acceptable level; (3) power market conditions that would preclude system operations required for ESA compliance; (4) testimony indicating that BPA would bear most of the cost of the Corps' compliance with Clean Water Act requirements under a district court ruling; and (5) new projections from fisheries managers indicating that the cost of BPA's compliance with the ESA under a new biological opinion made BPA's overall fish and wildlife costs estimates more than \$300 million per year too low. *See id.* at 1051-52. The court also found significant the fact that most of this evidence came from expert fish and wildlife managers. *Id.* at 1051.

The present circumstances in the BP-22 rate case are vastly different from those in *Golden NW*. First, the fish and wildlife cost estimates in the BP-22 rate case derive not from a range of uncertain alternatives, but from updated information, such as the Selected Alternative in the CRSO EIS ROD. The CRSO EIS ROD incorporates the most recent costs associated with implementing certain non-operational conservation measures intended to benefit species listed under the ESA and consulted upon under the ESA, which were, in turn, rolled into BPA's BP-22 power rates. As BPA Staff explained:

The CRSO EIS also provided operational assumptions used in the BP-22 initial proposal rate case modeling, including estimated spill volumes at each project that produce a certain level of total dissolved gas throughout the year. The Biological Opinions (BiOps) provided the rate case assumption of including periodic off-season surface spill in October, November, and March at the four lower Snake River projects and McNary Dam for downstream passage of adult steelhead and bull trout.

Mandell *et al.*, BP-22-E-BPA-46, at 4.

Moreover, the Mitigation Action Plan attached to the CRSO EIS ROD includes several actions BPA agreed to fund as part of the 2020 NMFS Columbia River System Biological Opinion (BiOp) and the 2020 USFWS Columbia River System BiOp. *See* CRSO EIS ROD, Attachment 1.

Second, unlike the stale cost estimates at issue in *Golden NW* (that were almost three years old by the time of the final rate determination), the CRSO EIS cost estimates used here were published at the end of September 2020 – only 10 months ago – and have been reconsidered and affirmed as recently as April 2021 for veracity as inputs in the rate case. *See* IPR Closeout Report, BP-22-M-IE-02-AT04, at 13; IPR 2 Closeout Report at 4; *see also* IPR 2 Workshop Presentation, BP-22-M-ID-02-AT03, at 44.

Third, while the Environmental Parties make general, bare assertions that BPA's fish and wildlife funding levels *may* be too low, they do not offer the sort of support for their contention analogous to the evidence that expert fish and wildlife managers proffered in the rate proceedings leading up to *Golden NW* (*i.e.*, actual calculations of refined cost estimates, evidence that proposed rates will compromise ability to implement compliance actions). To the extent the Environmental Parties have raised concerns with BPA's cost estimates or fish and wildlife funding levels, BPA has directly addressed them in the IPR 2 Closeout letter. Those responses included the following explanations: (1) concerns over whether BPA's IPR estimates include compliance costs under the Clean Water Act were highly speculative because "neither the Corps nor Reclamation have identified any additional separate costs associated with the state of Washington's Section 401 certification, nor does the commenter identify any such costs"; (2) claims that BPA's fish and wildlife spending failed to meet its equitable treatment obligation with its IPR cost estimates were legally unsound, and in any event, unsupported because the commenter "provides no basis for their claim that BPA's current level of F&W funding is inadequate . . . [n]or . . . what amount of Bonneville funding would be needed to meet the obligations the commenter believes are being violated;" and (3) discussion about BPA's discretionary direct funding authority for the Lower Snake River Compensation Plan (LSRCP) costs, the extent of annual operation and maintenance expense costs expected to be recovered in the BP-22 rate period, and how BPA would cover the power-share of congressional appropriations for LSRCP capital work through repayments to the U.S. Treasury. IPR 2 Closeout Report at 9-11. *See also* P.L. 94-587 § 102, 90 Stat. 2917, 2921 (Oct. 22, 1976) (authorizing the Corps to construct the LSRCP hatchery facilities in 1976 as part of a Water Resources Development Act); Water Resource Development Act of 1986, P.L. 99-662, § 856, 100 Stat. 4082 (Nov. 17, 1986) (transferring jurisdiction of the LSRCP hatchery facilities, along with their operation and maintenance, to the U.S. Fish and Wildlife Service pursuant to the Chief of Engineers' recommendation in the Lower Snake River Fish And Wildlife Compensation Plan, Washington And Idaho Special Report, at 2-3 (Mar. 6, 1985)).

Thus, the BP-22 rate case proceedings are in a fundamentally different factual posture from those at issue in *Golden NW*. Nonetheless, the Environmental Parties attempt to portray BPA's projected *increase* in net secondary sales as the type of "changed circumstance" addressed in *Golden NW*, and based on that "changed circumstance," argue BPA must reassess (1) its equitable treatment of fish and wildlife; and (2) its funding commitments for the Council's fish and wildlife program. Environmental Parties Br., BP-22-B-ID-01, at 12-14. BPA addresses each of these arguments below.

Equitable Treatment

The Environmental Parties offer three reasons why a forecasted increase in net secondary revenue requires BPA to reassess whether it is providing equitable treatment. First, the Environmental Parties contend that a final rate determination is a final decision that significantly impacts fish and wildlife because it affords BPA the opportunity to devote a portion of projected surplus revenue to fish and wildlife spending. Second, the Environmental Parties argue that BPA must consider equitable treatment in deciding what

to do with projected revenue increases in this rate case. Environmental Parties Br., BP-22-B-ID-01, at 13. Finally, the Environmental Parties claim that “because the secondary surplus revenue forecast calls into question whether assumed fish and wildlife funding levels provide “equitable treatment,” it necessarily casts doubt on the reasonableness of BPA’s cost projections, raising the risk that BPA may underestimate its costs,” Environmental Parties Br., BP-22-B-ID-01, at 13-14, and suggest it is unreasonable to assume fish and wildlife funding from IPR provides equitable treatment. *Id.* at 14. (BPA notes that this last position begs the question by assuming that both projected revenues and fish and wildlife funding levels are relevant to fulfilling the equitable treatment mandate, and, based on those assumptions, concludes that the cost projections for complying with the mandate may be unreasonably low.)

All three of the Environmental Parties’ reasons fail for their reliance on the legally flawed premise that equitable treatment applies to rates or funding levels, as discussed in the evaluations of the previous issues.

In addition, as to the Environmental Parties’ first point, final rate decisions do not significantly affect fish and wildlife, as already discussed. Their second point belies relevant case law, which establishes that each power marketing decision does not have to show equitable treatment so long as on balance BPA shows equitable treatment on a system-wide basis. *See Nw. Env’tl. Def. Ctr.*, 117 F.3d at 1534 (“BPA need not undertake an equitable treatment analysis for every discrete power marketing decision . . .”). Thus, even if equitable treatment applied to ratemaking or fish and wildlife funding decisions, it would not apply to each financial decision, such as what to do with a portion of projected surplus revenues.

For the Environmental Parties’ third reason, even if additional revenue may be available to expend on fish and wildlife, this in no way affects the underlying mitigation costs that rates are set to recover; nor would such additional revenue affect the separate, independent nature of the equitable treatment mandate. These last points deserve elaboration.

The Environmental Parties suggest that the change in projected net secondary revenue requires BPA to adjust its projected costs accordingly to provide for equitable treatment. Environmental Parties Br., BP-22-B-ID-01, at 14. Under *Golden NW* the key inquiry was whether the projected *costs* were supported by substantial evidence available at the time rates were set; the Court found, in part, that BPA failed to consider changed circumstances as to those *costs*. But here, the Environmental Parties point to a projected *revenue* increase as the relevant changed circumstance and in doing so have not established any basis to question the underlying costs or whether the proposed rates adequately recover them. Instead, the Environmental Parties suggest:

[I]n light of the large secondary surplus revenue forecast, it is no longer reasonable to assume that the level of fish and wildlife funding from IPR provides equitable treatment, so BPA must revisit that assumption and then adjust the projected costs accordingly. A failure to do so will violate BPA’s duty to reasonably estimate its costs at the time it sets rates.

Id. at 14 (footnote omitted).

Even setting aside the faulty notion that equitable treatment is dependent on fish and wildlife funding levels, there is a striking disconnect in the Environmental Parties' argument here. That is, the Environmental Parties seemingly conflate *revenue* and *cost*, essentially suggesting, without support, that a change in revenue must also somehow effect a change in independent, underlying costs.

Similarly, the Environmental Parties seem to be under the mistaken impression that a change in revenue somehow changes the nature of the equitable treatment mandate, or even is relevant to what the mandate substantively requires. This argument likely stems from the Environmental Parties' misunderstanding of equitable treatment as relating to funding levels. In any event, tethering BPA's legal obligation under equitable treatment to its financial performance would be contrary to the Ninth Circuit's description of equitable treatment as an "independent" mandate. *Nw. Env'tl. Def. Ctr.*, 117 F.3d at 1532. Following the Environmental Parties' logic, if BPA's obligation to fish and wildlife *expands* during years when BPA's revenue exceeds expectation, should it not also *contract* when BPA's revenue projections fall short? If that were the case, BPA's obligation to fish and wildlife would be in constant flux. And while BPA is *projected* to see a healthy level of surplus revenue over this rate period, in eight of the past 13 years BPA's projected surplus revenues have been lower than the rate case forecast, with some deficits exceeding \$100 million. *See Fisher et al.*, BP-22-E-BPA-35, at 21. Tying BPA's obligation to provide equitable treatment to BPA's revenue projection would, thus, introduce a wholly new and unnecessary level of uncertainty as to the very nature of the equitable treatment responsibility.

The Environmental Parties also offer the misplaced suggestion that equitable treatment of fish and wildlife requires "even more" than full implementation of the Council's fish and wildlife program. *Environmental Parties Br.*, BP-22-B-ID-01, at 21 (claiming that BPA is "clearly out of compliance with the equitable treatment obligation" if flat fish and wildlife budgets threaten BPA's ability to "fully implement" the Council's program). The Council's program applies to three federal agencies in addition to BPA and, therefore, is beyond BPA's sole responsibility to implement. *See Pub. Util. Dist. No. 1 of Douglas Cnty. v. Bonneville Power Admin.*, 947 F.2d 386, 389 (9th Cir. 1991). But more importantly, the Environmental Parties' suggestion that fully implementing the Council's program is a necessary condition for equitable treatment misses the point of the applicable case law. True, in *Nw. Env'tl. Def. Ctr.*, the court recited its earlier holding that "BPA's responsibilities to protect fish and wildlife do not end even with complete adoption of the Council's Program." 117 F.3d at 1532. But the court did not hold that full implementation of the program is *necessary* for equitable treatment. In fact, the court went on to explain that because equitable treatment is an "independent" obligation, "a federal agency could not satisfy its equitable treatment responsibilities under paragraph (i) simply by adopting the Council's program under paragraph (ii). [Therefore,] *if the Council's Program fails* to ensure adequate fish survival, BPA would be required to take additional measures under paragraph (ii)." *Id.* (emphasis added, citations omitted).

In short, BPA could not rely solely on full adoption of a deficient Council Program to fulfill its separate equitable treatment responsibility. In *Confederated Tribes*, the court clarified

further: “While we held that relying on the Council’s program is not *sufficient* to satisfy the equitable treatment mandate, we did not hold that reliance on the program was improper.” 342 F.3d at 934 (emphasis added). Nor did the court find the Council’s program *necessary* for equitable treatment. As such, even if BPA does not fully fund or fully implement the Council’s program, that fact alone does not establish non-compliance with the independent equitable treatment mandate pertaining to system operations and management.

Finally, as explained in the evaluation of Issue 4.2.2, the function of BPA ratemaking is not to adjust projected costs. Indeed, there is hardly a basis to do so, absent a showing of relevant new information or materially changed circumstances, which is not present here. *See* Issue 4.2.2 (considering and addressing the Environmental Parties’ various assertions as to the need for higher fish and wildlife cost estimates in BPA’s projections).

An increase in projected net secondary revenue is not a changed circumstance that would require BPA to reassess its fish and wildlife spending levels for purposes of equitable treatment.

Council Program

The Environmental Parties also argue that the projected increase in net secondary revenue requires BPA to reconsider its fish and wildlife spending levels in order to fulfill its responsibility, under 16 U.S.C. § 839b(h)(11)(A)(ii), to take the Council’s Fish and Wildlife Program into account at each relevant stage of decision-making and to the fullest extent practicable. Environmental Parties Br., BP-22-B-ID-01, at 14. As an initial matter, BPA notes that, like “equitable treatment,” the requirement to take the Council’s Program into account also arises under the umbrella of paragraph 4(h)(11)(A). Specifically:

(A) The Administrator and other Federal agencies responsible for managing, operating, or regulating Federal or non-Federal hydroelectric facilities located on the Columbia River or its tributaries shall —

...

(ii) exercise *such responsibilities*, taking into account at each relevant stage of decision-making processes to the fullest extent practicable, the program adopted by the Council under this subsection.

16 U.S.C. § 839b(h)(11)(A) (emphasis added).

This paragraph applies in the context of BPA’s *management* and *operation* responsibilities with respect to the federal hydropower system of the Columbia River basin – that is, to the power marketing actions of the system. *See* Issue 4.2.1.

In their brief, the Environmental Parties appear to concede that BPA has already taken into account the Council’s Fish and Wildlife Program in their claim that BPA must take the Program into account “*again*.” *See* Environmental Parties Br., BP-22-B-ID-01, at 14 (emphasis added). BPA agrees that it has already taken into account the relevant operations and management provisions of the Council’s Program. *See* CRSO EIS ROD § 5.5.2 (describing how BPA has taken the Council’s Program into account during the

CRSO EIS process).²³ However, BPA disagrees that the ratemaking process is a “relevant stage of decision-making” in the exercise of system operation and management responsibilities such that a renewed look at fish and wildlife spending levels or the Council’s Program would be necessary or appropriate within the rate case or as a result of a projected increase in net secondary revenue.

First, the rate case is not a “relevant” stage of decision-making under Section 4(h)(11)(A)(ii) of the Northwest Power Act. As explained in the evaluation of Issues 4.2.1 and 4.2.2, and contrary to the Environmental Parties’ assertion that it is a “stage at which BPA has discretion to *take actions* that will affect fish and wildlife,” Environmental Parties Br., BP-22-B-ID-01, at 14 (emphasis added), a rate case is simply a process conducted by BPA to set rates to recover costs and does not itself undertake or prescribe system operations and management actions or otherwise make decisions affecting fish and wildlife. And as explained in the evaluation of Issue 4.2.2, costs included for recovery through rates flow from inputs arising outside of the rate case. The purpose of the rate case is not to re-evaluate or second-guess those inputs, absent compelling evidence showing a need.

The Environmental Parties rely on *Nat’l Wildlife Fed’n v. FERC*, 801 F.2d 1505 (9th Cir. 1986) to support their contention that BPA’s ratemaking process is a “relevant stage of decision-making” under 16 U.S.C. § 839b(h)(11)(A)(ii). The FERC permitting process was at issue in that case, and the court emphasized that “issuance of preliminary permits and the formulation of their articles are of central importance in [FERC’s] process of licensing.” *Nat’l Wildlife Fed’n v. FERC*, 801 F.2d at 1514. In contrast, as explained in the evaluation of Issue 4.2.1, BPA’s ratemaking is focused on cost recovery. Nothing in BPA’s ratemaking process deals with the development or planning of fish and wildlife mitigation actions; rather, it focuses on recovering costs. Therefore, unlike a FERC permitting process where mitigation can be prescribed, there would be no point in considering the Council’s program *again* in setting BPA’s rates.

In addition, as with the equitable treatment mandate, BPA finds it sensible and appropriate to address consideration of the Council’s Program in the context of decisions relating more directly to fish and wildlife actions, rather than in a process that merely recovers the costs of such actions. *See, e.g.*, CRSO EIS ROD § 5.5.2.

Furthermore, the Environmental Parties fail to explain why an anticipated increase in revenue requires reconsideration of fish and wildlife costs in order to satisfy BPA’s duty to

²³ Indeed, over time the Council amended into its program the operations BPA proposed and adopted through its ESA Section 7(a)(2) consultations. By 2013, the Ninth Circuit was able to observe that, “the [Council’s] 2009 Program did not include plans of detailed hydrosystem operations for fish and wildlife because the federal agencies . . . had already produced detailed plans for the operations of each facility intended to improve conditions for fish and wildlife affected by the hydrosystem.” *Nw. Res. Info. Ctr. v. Nw. Power Planning Council*, 730 F.3d 1008, 1014 (9th Cir. 2013) (*NRIC*). The operations in the CRSO EIS ROD Selected Alternative and associated ESA consultations expand on prior CRS operations that the Council had adopted in its Fish and Wildlife Program. In that way, BPA has taken the Council’s Program into account as called for in Section 4(h)(11)(A)(ii). *See* CRSO EIS ROD § 5.5.2 at 51 (describing the Council’s frequent endorsement of CRS management and operation actions from biological opinions and various implementation agreements).

take the Council's program into account. The Environmental Parties disagree with BPA's current fish and wildlife funding levels and advocate for increased fish and wildlife funding in the context of the Council's Program. See *Environmental Parties Br.*, BP-22-B-ID-01, at 14-15, 21. But, to support their argument, Environmental Parties would need to show that rates are inadequate to cover BPA's projected costs or that BPA's cost estimates are too low to fulfill the agency's compliance obligations.²⁴ The Environmental Parties have shown neither here. As explained above and in the evaluation of Issue 4.2.2, they offer only conclusory speculation on the adequacy of fish cost estimates, and nothing in the way of reports, analysis, or calculations, comparable to those that were dispositive in *Golden NW*, that might prompt (or even allow) BPA to revisit its fish cost estimates yet again, after having done so as recently as IPR 2. The vague evidence that the Environmental Parties have posited has been considered and addressed; it would defy prudent business practice to accept such speculation and vague assertions of unconfirmed responsibilities as an appropriate basis for revisiting, let alone revising, projected costs.

In attempting to support their allegation of a shortfall in BPA's mitigation funding with respect to the Council's Program, the Environmental Parties cite portions of the 2020 Addendum to the Council's Program. See, e.g., *Environmental Parties Br.*, BP-22-B-ID-01, at nn.77& 86.²⁵ The Environmental Parties miss the Council's broader view as to the costs that may be associated with new Program provisions: the Council said it "is confident that most, if not all, of the additional needs identified in the 2014 program, and reflected in this addendum, may be met within an overall program-management and cost-management approach that prevents program costs from rising above the rate of inflation." *NW Power and Conservation Council, 2020 Addendum to the 2014 Columbia River Basin Fish and Wildlife Program, Findings on Recommendations at 45 (Oct. 2020)*, available at <https://www.nwcouncil.org/sites/default/files/2020-9.pdf>. And specifically with regard to the additional mitigation expenditures proposed in the Upper Columbia, the Council noted that "[t]hose additional expenditures can be balanced over time by judicious management of their ramp-up and finding further program efficiencies that do not affect substantive work." *Id.* The Council did not say BPA's costs were likely to be higher than forecast or that implementing the new work would require BPA to increase its overall funding for fish and wildlife mitigation, or that it recommended all the work be done in the coming rate period. See *id.* at 39 (suggesting that an effort to increase mitigation should begin over the next five years). Thus, the Council's Fish and Wildlife Program provisions cited by the Environmental Parties do not establish that BPA's likely costs for fish and wildlife mitigation will be higher than projected during the BP-22 rate period.

Additionally, while *Golden NW* has little in common with this rate proceeding, *NRIC* is instructive. In *NRIC*, the court rejected a challenge to the Council's newly finalized

²⁴ As mentioned above, BPA has several risk mechanisms in place to ensure cost recovery in the event of unexpected cost increases. These include: financial reserves, the FRP Surcharge, CRACs, debt financing options, and the option to institute Section 7(i) proceedings to develop rates, among other options.

²⁵ BPA provided written comments on (and continues to question) certain recommendations for amendment of the Council's program and the draft program, available on the Council's website at <https://www.nwcouncil.org/fw/program/2020addendum>.

Sixth NW Power Plan where the petitioner alleged that the Council failed to give fish and wildlife “due consideration” when it did not independently consider and give significant weight to the needs of anadromous fish when formulating the power plan. 730 F.3d at 1015-18. The petitioner argued that incorporating the recently completed 2009 Columbia River Basin Fish and Wildlife Program into the power plan fell short of the Council’s responsibility to consider fish and wildlife needs in the power planning process. Instead, the petitioner argued that if, through the power planning process, the Council learns of “capacity for further fish and wildlife enhancements,” then it “must consider whether such enhancements would serve the [Northwest] Power Act’s goal of furthering fish and wildlife interests . . .” *Id.* at 1015-16. The petitioner emphasized that because the power planning process revealed the region had a greater capacity for energy conservation than previously thought, that could in turn lead to more capacity for fish and wildlife mitigation than the 2009 Fish and Wildlife Program had considered. The court nevertheless rejected the petition because nothing in the Northwest Power Act required the Council to consider new fish and wildlife measures in the process of adopting a power plan. *Id.* at 1018.

Here, too, the Environmental Parties claim in the rate case that BPA must consider greater spending levels for fish mitigation in light of surplus power revenue forecasts increasing unexpectedly. And like the petitioner in *NRIC*, they cannot cite a statutory mandate requiring BPA to consider additional fish mitigation during the ratemaking process, particularly when BPA has already considered the Council Program, as the Environmental Parties acknowledge. Following *NRIC*, BPA rejects the contention that, to satisfy its responsibility to take the Council Program into account, it must consider additional spending for fish and wildlife when surplus sales revenue forecasts increase unexpectedly during a rate proceeding.

Brief on Exceptions

In their Brief on Exceptions, the Environmental Parties continue to insist that BPA “must revisit its projected fish and wildlife spending levels in light of the unexpectedly large secondary surplus revenue forecast.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 21. In arguing their position, they attack two points BPA made above. One, BPA’s argument that the Environmental Parties, unlike the petitioners in *Golden NW*, have not shown that projected funding levels for fish and wildlife mitigation efforts are inadequate. To this the Environmental Parties’ argument in its simplest form “is that the projected secondary revenue forecast is so large” that it is “unjustifiable” for BPA to continue to adhere to IPR spending levels. *Id.* at 23. The other issue they address is BPA’s argument that the cost projections incorporated into this rate case, unlike the fish and wildlife cost estimates at issue in *Golden NW*, are not stale and no evidence on the record provides a reasonable basis or need to revisit those projections. The Environmental Parties response to this is that the estimates are no longer reliable “because they were developed before BPA realized that it was facing a huge secondary surplus revenue boon.” *Id.* at 24 (emphasis omitted).

With both of these arguments, the Environmental Parties mistake either the nature of surplus revenue, or the necessary timing of the forecast in the ratemaking process. Each

point merits explanation, because each undermines the foundation for the Environmental Parties' objections to BPA's rates decision.

In their Brief on Exceptions, the Environmental Parties appear to misunderstand the first of BPA's arguments noted above when they claim that "the nature of the equitable treatment mandate is such that a particular level of funding that is legally 'adequate' may become legally 'inadequate' thanks to changed circumstances." *Id.* at 23. This is effectively the same argument from their Initial Brief, claiming that the projected secondary revenue is "so large" that it "changed the landscape" (or the "equitable treatment 'denominator'"), requiring that BPA's planned funding levels be "revisited" for equitable treatment. *See id.* at 23-25; Environmental Parties Br., BP-22-B-ID-01, at 13 ("the secondary surplus revenue forecast changes the landscape: the equitable treatment mandate requires BPA to treat fish equitably on the whole, and that whole now includes a huge surplus that BPA could devote (at least in part) to fish and wildlife.") (internal quotation and citations omitted). The Environmental Parties' argument again hinges on the notion that the surplus power revenue forecast constitutes a "changed circumstance" that allegedly undermines the reliability of BPA's cost estimates. Environmental Parties Br. Ex., BP-22-R-ID-01, at 24.

BPA has already discussed that the "changed circumstance" theory stems from *Golden NW*, which was concerned with the adequacy of BPA's cost recovery in rates, independent of expected secondary revenue. *Supra* Issue 4.2.2.

To further emphasize what BPA states in Issue 4.2.5, in Direct Testimony, BPA's financial staff addressed the nature of the secondary revenue forecast and its unpredictability.

That forecast is more than \$100 million per year more than it was in the last rate period. While this reflects the results of our traditional application of our models, we recognize that *this increase in secondary revenue is only a forecast. Markets can change and BPA's inventory – which relies on water and snow pack – can change dramatically from year to year. Such a large increase in secondary revenue, then, gives us some pause.*

Fisher *et al.*, BP-22-E-BPA-15, at 22 (emphasis added).

Moreover, the reason the forecast caused staff to "pause" was because BPA's standard deviation from its forecast to the actual amount of surplus sales has averaged "about \$125 million to \$180 million, depending on the rate period, with \$180 million representing the standard deviation consistent with the BP-22 Initial Proposal. Fisher *et al.*, BP-22-E-BPA-35, at 22; *see also id.* at Attachment 2 (Data Response MS-BPA-30-118).

The nature of secondary revenues is that they are unpredictable, and that unpredictability arises from causes beyond BPA's control. Such volatility and uncertainty would not seem to be an ideal way to support an ongoing mitigation program. Indeed, it would be a poor business practice to base program budgets on projections of a volatile and historically difficult-to-predict revenue stream – which is why BPA does not do that for *any* of its spending programs – a practical (but potentially costly) consideration the Environmental Parties overlook.

The Environmental Parties lack the caution BPA's staff exhibited in the face of the unknown. The Environmental Parties' arguments, and their proposed solution, assume the revenues will materialize as forecast. They fail to appreciate the risk or potential consequences of planning to fund new fixed costs – in this case setting aside revenues for their proposed new or expanded mitigation actions – with an uncertain stream of funds. And the \$100 million increase in forecasted surplus revenues – that the Environmental Parties call a “new” and “substantial,” landscape-changing, “huge expected boon in secondary surplus revenue” – falls well below the average standard deviation of a \$125 million to \$180 million difference between the forecast and actuals.

Ultimately, the Environmental Parties' proposal ignores the balancing of purposes that the Northwest Power Act mandates when they tip the scale so heavily for fish without regard to ensuring the region has an adequate, efficient, economical, reliable power supply. *See e.g.*, 16 U.S.C. § 839(2); *see also NRIC v. Nw. Power Council*, 35 F.3d at 1378 (“the Act states that fish and wildlife protection measures cannot jeopardize “an adequate, efficient, economical, and reliable power supply”). BPA cannot ignore the risk posed by the uncertainty of secondary revenue forecasts nor the Northwest Power Act mandate to balance the needs of fish and power.

Despite the varied descriptions Environmental Parties use to describe the surplus revenue forecast, they miss its essence. It is a forecast. It comes with a \$125 million to \$180 million standard deviation. It is not money in the bank; it may be a boon – or a bust. And while the forecast exceeded untested assumptions based on prior rate cases, it was not new information related to actual costs, legal obligations, or flaws in analysis that could lead BPA to revisit its rates proposal or change its planned spending level for any of its programs.

The drivers behind the timing of the secondary revenue forecast also undermine the Environmental Parties' arguments for a new cost analysis. The logical sequencing of the rate design process is crucial context. Secondary revenues derive from the sale of power available *after* all other FCRPS operation mandates and related agreements have been met. It is what is left over, it is not firm – it is “secondary.” Therefore, the secondary revenue forecast can come only after BPA decides on its other operations, including those operations identified to mitigate for the effects of the Selected Alternative in the CRSO EIS ROD. BPA knew it could not have reliable secondary surplus sales revenue forecast until *after* it executed the CRSO EIS ROD. That is because prior to completion of the CRSO EIS ROD and choosing the Selected Alternative, BPA did not know what mitigation actions it would agree to take, or their estimated costs.²⁶ Any estimate prior to completing either of those steps would be preliminary at best and need to be subject to revision. As BPA staff told Environmental Parties in response to a data request, “[p]rior to developing the updated

²⁶ In footnote 93 of their Brief on Exception, Environmental Parties raise a point that BPA here clarifies: funding levels were not decided in the CRSO FEIS or ROD. Environmental Parties Br. Ex., BP-22-R-ID-01, at 24 n.93. Rather, the ROD memorialized the decision regarding which operation, structural and mitigation actions Co-Lead Agencies would implement, after the agencies examined the alternatives and compared their effects and costs in the CRSO FEIS.

secondary market forecast, BPA Staff and many stakeholders *assumed* secondary revenue would be at or below levels included in BP-20 rates [and] . . . believe[d] a 2-4 percent rate increase would likely be needed to recover BPA's costs in BP-22." Motion to Admit Data Responses into Evidence, BP-22-M-ID-01, Attachment, Data Response ID-BPA-30-9 (emphasis added). In reality, the secondary revenue forecasts were not "new" within the context of BP-22 rate development; they were simply *the* secondary revenue forecasts for BP-22 period. Indeed, BPA did not base its fish and wildlife funding projections developed in the IPRs on any expectation of secondary revenues because cost projections are developed before any rate proposals begin. Therefore, the secondary revenue forecast cannot represent a "changed circumstance" with respect to fish and wildlife funding because there was no established secondary "forecast" at the time BPA developed the fish and wildlife funding projections.

Thus, where the Environmental Parties see the secondary revenue forecast as a landscape-changing realization effecting a change in circumstances, BPA sees a reasonably timed, logical step in the rate development process. The difference between the secondary revenues BPA staff assumed prior to making a forecast, and the actual forecast, is in no meaningful way a "new" or "changed circumstance." Obtaining forecast results that exceed preliminary, untested assumptions, yet fall well below the average standard deviation between forecast and actuals, does not by itself justify revisiting the proposed rates or the settlement.

Intertwined with their main arguments on Section 4.2.3 of the Draft ROD, the Environmental Parties restate and recast several other points originating in their Initial Brief.

First, they say the rate case offers BPA the opportunity to use its "discretion at this time to act in a way to further implement the Council's program." Environmental Parties Br. Ex., BP-22-R-ID-01, at 26. Then they say BPA should revisit its cost projections because the agency has "broad authority to establish rates in conformity with its conflicting obligations . . ." *Id.* What these pleas omit is the need to fulfill a statutory mandate through the exercise of discretion. The Environmental Parties do not (and cannot) tie these proffered exercises of discretion to a legally enforceable need to do so. *See Confederated Tribes*, 342 F.3d at 933 (citing *NEDC*, 117 F.3d at 1533-34 (concluding it was premature to consider whether BPA violated the equitable treatment mandate in refusing to dedicate a portion of water for fish when the vast majority of BPA's share of the water was unallocated)). A failure to exercise discretion in the absence of a statutory mandate is not actionable. For judicial review of an agency's failure to act under the Administrative Procedure Act, a petitioner must at least show "agency recalcitrance . . . in the face of clear statutory duty or . . . of such a magnitude that it amounts to an abdication of statutory responsibility." *Id.* at 930 (citing *Mont. Wilderness Ass'n, Inc. v. U.S. Forest Serv.*, 314 F.3d 1146, 1150 (9th Cir. 2003) (internal quotation marks and citation omitted)).

In another respect, the Environmental Parties mischaracterize BPA's position to make their point: "BPA contends that it need not take the Council's fish and wildlife program into account, when *deciding what to do with the large secondary surplus revenue forecast.*"

Environmental Parties Br. Ex., BP-22-R-ID-01, at 25 (emphasis added). To the contrary, as BPA has explained above, that “decision” is not even at hand or being made in this rate case. Indeed, what can be done with secondary revenues necessarily depends on whether they are ever in hand – something not known at this time. This is why the settlement provision addressing their potential future use is conditional, and why BPA is not premising *any* program’s budgets on them.

In addition, the Environmental Parties rely on a prevailing theme throughout their Brief, but particularly here: when BPA can do more, it must do more – regardless of the “what.” Environmental Parties continue to decry how “it is unfathomable to think that BPA is doing all it can to implement the program.” *Id.* at 28. To remedy this situation, they “have suggested several specific ways that increased funding could help improve implementation of the Council’s program.” *Id.* at 27 (emphasis omitted). Indeed, the Environmental Parties’ lodestar still appears to be whether BPA’s proposed fish and wildlife funding levels and rates are adequate to “fully implement” or “better implement” the Council’s program.

As explained above, this simply is not the function of the rate case – the decision at hand – which is to recover costs, not decide what costs to incur. *See Supra* Issue 4.2.2.

In their Brief on Exceptions, the Environmental Parties reiterate that BPA could (and in their view “must”) do more to benefit fish. In support of their argument, they highlight a quote from a presentation that the Nez Perce Tribe made to the Council in July 2021. Environmental Parties Br. Ex., BP-22-R-ID-01, at 16-17. The presentation cited, however, is not a prescription, project, or proposal for any particular mitigation action from the Council, or cost to BPA. *Id.* And given its focus on overall status of the species, which is affected by numerous factors and the responsibility of many entities, this is not an appropriate indicator of the extent of BPA’s responsibility to mitigate, and therefore to recover, costs for doing so.²⁷

With regard to increased mitigation costs arising from ongoing litigation, the situation remains as generally described above in Section 4.2.3: Environmental Parties cannot say when a court would rule, what it would rule, how that would affect BPA and its ratepayers, or whether any costs related to the ruling would fall within the BP-22 rate period.

The other new actions Environmental Parties submit in their Brief on Exceptions all suffer the same shortcomings. *See* Environmental Parties Br. Ex., BP-22-R-ID-01, at 15-17, 28-29. Whether toxic clean-ups, northern pike suppression, or fish screens on irrigation diversions, the Environmental Parties fail in the first instance to show that BPA *must* fund

²⁷ In their footnote 115, the Environmental Parties observe that the Council did not assess whether any particular amount of BPA funding is sufficient to meet program goals and the Northwest Power Act. Environmental Parties Br. Ex., BP-22-R-ID-01, at 28 n.115. BPA has discussed such matters often in the appropriate forums, such as the CRSO EIS and comments on the Council’s 2014 Program and 2020 Addendum. In sum, the program guides four agencies, not just BPA. And the Council has adopted goals and objectives that go beyond the mandates of the Northwest Power Act or any obligations BPA has under its organic statutes. The decline of fish stocks, the failure to meet the program goals and objectives, or room to improve program implementation offer little insight into the appropriate size of BPA’s funding levels, the effectiveness of BPA’s mitigation efforts, or the need for the agency to increase either one.

them to comply with the law. Even if BPA may eventually incur these costs, the Environmental Parties provided no evidence of whether the costs would accrue during the course of the BP-22 rate period or that BPA could not cover them within the existing proposed budget and rate structure. Considered individually or taken together, these areas of speculative future increased costs continue to fall short of providing substantial evidence that BPA will likely need to do more to fulfill its statutory mitigation mandates during the rate period. They do not justify revisiting the proposed rate settlement.

Decision

BPA's projected increase in net secondary revenue does not constitute a "changed circumstance" that would require BPA to reconsider its fish and wildlife funding levels in order to satisfy its Northwest Power Act obligations to fish and wildlife.

Issue 4.2.4

Whether BPA's policy objectives outlined in the Strategic Plan and cost projections from the IPR process become reviewable decisions when BPA issues its final rate determinations.

Parties' Position

The Environmental Parties argue that "[t]his rate proceeding is the final step in a series of actions culminating in a 'final rate determination . . .'" Environmental Parties Br., BP-22-B-ID-01, at 3. They argue that "BPA's discretionary policy decisions in this rate proceeding are also guided by the results of earlier processes." *Id.* at 4. In particular, they argue that BPA's Initial Proposal to hold power rates flat is "heavily influenced by" the "long-term objectives and goals" found in the 2018–2023 Strategic Plan. *Id.* The Environmental Parties argue that while BPA assumes costs "consistent with those developed during the [IPR] process," it should have updated fish and wildlife spending levels in light of the increased net secondary revenue forecast. *Id.* at 3, 5. The Environmental Parties acknowledge that BPA conducted an IPR 2 process in March and April 2021 and considered certain fish and wildlife funding issues during the IPR 2 process. *Id.* at 5 n.28. The Environmental Parties argue that judicial review of BPA's Strategic Plan, its most recent IPR process, and other intermediate decisions feeding into this rate case will be available as part of the review of BPA's final rate determination. *Id.* at 18.

In their Brief on Exceptions, the Environmental Parties argue that BPA has "utterly misunderstood" their argument. Environmental Parties Br. Ex., BP-22-R-ID-01, at 29. The Environmental Parties contend that they are not asserting that IPR or the Strategic Plan are final actions or become so with the final rate determination. *Id.* at 30. Instead, the Environmental Parties contend "the point made by the Environmental Parties is that the Strategic Plan and IPR process are reviewable as part of the review of BPA's final rate determination insofar as they fed into that rate determination." *Id.*

BPA Staff's Position

This is a legal issue raised in the Environmental Parties' initial brief.

Evaluation of Positions

Foundational to the Environmental Parties' argument is the view that BPA's Strategic Plan and projected funding levels in IPR become final agency actions by virtue of the Administrator's decision on BP-22 rates. The Environmental Parties assert that the Strategic Plan and IPR are "intermediate decisions" that become final and reviewable with the underlying rates, and as such, are subject to BPA's fish and wildlife legal obligations, such as "equitable treatment." *Id.* As explained below, this view is flawed because BPA's Strategic Plan and IPRs are not final, reviewable agency actions and BPA's final rate determinations in this case do not convert them into such actions.

Strategic Plan

The Environmental Parties argue that BPA's Strategic Plan is a "final" decision that will become reviewable with the final rate determination. *Id.* For support, they cite *Industrial Customers of Nw. Utils. v. Bonneville Power Admin.*, 408 F.3d 638 (9th Cir. 2005) (*ICNU*). *Id.* at 17-18. The Court in *ICNU* relied on the oft-cited Supreme Court case of *Bennett v. Spear*, 520 U.S. 154, 117 S.Ct. 1154, 137 L.Ed.2d 281 (1997), in which the Supreme Court set forth a two-part test for determining whether an agency action is final:

First, the action must mark the 'consummation' of the agency's decision making process – it must not be of a merely tentative or interlocutory nature. And second, the action must be one by which 'rights or obligations have been determined,' or from which legal consequences will flow.

117 S. Ct.at 1168 (citations omitted). The *ICNU* court further explained that "[t]he core question is whether the agency has completed its decision-making process, and whether the result of that process is one that will directly affect the parties." *ICNU*, 408 F.3d at 646 (citations omitted). The court also described the type of factors that indicate the agency's decision is final: "whether the [action] amounts to a definitive statement of the agency's position, whether the [action] has a direct and immediate effect on the day-to-day operations of the party seeking review, and whether immediate compliance [with the terms] is expected." *Id.* (citations omitted).

Applying these factors to BPA's Strategic Plan shows that it is not a final agency action under *Bennett v. Spear* or *ICNU*. As the Environmental Parties acknowledge in their brief, BPA's Strategic Plan includes "long-term objectives and goals." Environmental Parties Br., BP-22-B-ID-01, at 4. Regarding fish and wildlife costs, BPA's 2018–2023 Strategic Plan sets out a high-level strategy for BPA to "continue to be deliberate about controlling Fish and Wildlife Program costs, consistent with sound business principles and in the context of BPA's competitive position, while assuring that fish and wildlife receives equitable treatment with the other purposes of the system, as required by the Northwest Power Act." Strategic Plan, BP-22-M-ID-02-AT01, at 41. To do this, BPA expressed a general intent to operate within existing budgets adjusted by inflation. *Id.* It is important to note that this general objective applies to *all* of BPA's future budgets – not just fish and wildlife. *See* Strategic Plan, BP-22-M-ID-02-AT01, at 12. But, even more, this aspirational goal is not a final call on what BPA actually must spend to meet its various fish and wildlife obligations.

If BPA must take actions to meet its fish and wildlife responsibilities, nothing in the Strategic Plan precludes BPA from doing so.

Moreover, the Strategic Plan itself has no legal effect on day-to-day operations. No costs are established in the plan nor are any specific measures adopted or rejected. The Strategic Plan simply provides overarching policy guidance that, by its own terms, would be evaluated and subject to additional review in appropriate forums. *See id.* at 61. The Strategic Plan fails both prongs of the *Bennett v. Spear* test for finality. First, it is a general announcement of agency priorities that does not determine any final policy decisions (such as the rates adopted in this proceeding). Second, it includes high-level goals that do not determine rights or obligations from which legal consequences will flow.

Lastly, the non-final nature of the Strategic Plan does not change when BPA issues its final rate determinations. The Strategic Plan is a general statement of policy. To that end, there is nothing in the record that demonstrates BPA has abandoned its ratemaking discretion in favor of executing the Strategic Plan through its rate decisions. The Environmental Parties claim BPA's rate proposals include features mentioned in the Strategic Plan, such as "revenue financing" and "debt management." Environmental Parties Br., BP-22-B-ID-01, at 4. But these observations are of little legal import. The Strategic Plan describes many different general objectives for BPA to pursue. BPA's rate decisions to employ "revenue financing" while "holding rates flat" in this case arose from the specific facts and issues presented in the record, *see Fisher et al.*, BP-22-E-BPA-15, at 2–3, and not because of blind adherence to implementing the Strategic Plan.²⁸ The Strategic Plan is not a final, reviewable agency decision and no decision BPA has made in the final rates determination has changed that.

Integrated Program Review

The Environmental Parties next raise a number of non-specific challenges that BPA's fish and wildlife cost projections are too low or otherwise not sufficient to meet BPA's obligations. Environmental Parties Br., BP-22-B-ID-01, at 16-18. In support of their arguments, the Environmental Parties assert that BPA's projections of fish and wildlife funding from the IPR are intermediate decisions that become "final" decisions with the final rate determination. *Id.* at 18. This challenge is most properly viewed as a collateral attack on the decisions made by the agencies in the CRSO EIS process. *See* Issue 4.2.1. Nevertheless, insofar as the Environmental Parties argue that the fish and wildlife costs that BPA projects in the IPR process are challengeable as part of the BP-22 decision, their view is incorrect. Specifically, the Environmental Parties misconstrue the IPR process, BPA's budgeting process, and applicable law.

²⁸ The Environmental Parties also claim that BPA's fish and wildlife funding projections from IPR stem "in large part" from the Strategic Plan. *See* Environmental Parties Br., BP-22-B-ID-01, at 4. This issue is subsumed in the discussion of the non-finality of BPA's IPR projections. BPA's IPR funding projections are non-final and unreviewable, just as general policy guidance stemming from the Strategic Plan that is used to inform the development of those projections is equally non-final and unreviewable.

First, the IPR processes are not “intermediate” decisions on BPA’s spending levels on any program nor do they fix any funding obligations. As described in Section 1.2.1 of this Final ROD, IPR is designed to provide an orderly and transparent process where BPA can receive stakeholder feedback on its projections of various programmatic costs for the two-year period covered by BPA’s ratemaking. Importantly, IPR does not end the spending estimate process, and it is fully understood and stated in IPR that these projections may change. The Closeout Report BPA issues at the end of the IPR process is clear about the limited ratemaking purpose of the projections: “The projected program levels described in this close-out letter and report reflect BPA’s estimate of the appropriate spending levels, i.e., costs, to assume in establishing new power and transmission rates.” IPR Closeout Report, BP-22-M-ID-02-AT04, at 13; *see also* IPR 2 Closeout Report at 12. The transitory nature of these estimates is directly addressed in BPA’s IPR Closeout Report: “This close-out of the IPR process does not complete BPA’s decision-making process on spending levels. Adjustments to BPA’s spending projections may occur after the conclusion of the IPR.” IPR Closeout Report, BP-22-M-ID-02-AT04, at 13. The changeable nature of these programs underlie the reason these spending decisions are discussed in the informal IPR stakeholder process and expressly excluded from the scope of BPA’s Section 7(i) formal administrative proceeding: “Bonneville’s projections of its program costs and spending levels are not determined in rate proceedings.” 85 Fed. Reg. 77,189, 77,190 (Dec. 1, 2020). Simply put, there is no need to litigate in the rate case something that will be finally determined in other processes.

Second, the Environmental Parties’ argument misses that BPA’s *budgeting* process is not complete through IPR. BPA’s IPR projections are, ultimately, budget recommendations. Those recommendations are informed by various processes and sources, such as the Bureau, Corps and the public comment process from IPR. They also change through BPA’s detailed quarterly and annual budgeting processes that necessarily fluctuate based on changing business conditions and other factors. Furthermore, the BPA Administrator submits an annual budget to Congress, 16 U.S.C. § 838i(b), and those budget estimates are included in the federal budget, where they are subject to further review by the U.S. Department of Energy, the President, and the Congress. Changes may occur during any one of these reviews. *See, e.g.*, Government Corporate Control Act, 31 U.S.C. § 9103 (under which BPA submits a “business-type budget” to the President, and the President then “shall submit the budget . . . (as changed by the President)” as part of the annual Federal budget submission to Congress.) In short, the projections used in ratemaking are not “definitive”; rather, they are one step in the budgeting process.

Third, and most importantly, the Environmental Parties’ contentions also fail as a matter of law. Legally, BPA’s funding proposals from IPR are not final decisions nor do they become final when BPA sets rates. Agency funding recommendations are not final agency decisions. As the U.S. Court of Appeals for the D.C. Circuit has explained, “[an] agency’s proposal to Congress, developed to secure the funds, may serve as a useful planning document, but it is not a ‘rule’ – that is, ‘an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy.’” *Fund for Animals, Inc. v. U.S. Bureau of Land Mgmt.*, 460 F.3d 13, 20 (D.C. Cir. 2006)

(citing 5 U.S.C. § 551(4); *Indep. Equip. Dealers Ass'n*, 372 F.3d 420, 428 (D.C. Cir. 2004)). The U.S. Supreme Court has also found that agency proposals to Congress or recommendations on how to allocate broad appropriations are not reviewable final agency actions. See, e.g., *Dalton v. Spencer*, 511 U.S. 462, 468-71 (1994) (holding that recommendations of Defense Base Closure and Realignment Commission were not reviewable as final agency actions); *Lincoln v. Vigil*, 508 U.S. 182, 193 (1993) (citing *Heckler v. Cheney*, 470 U.S. 821, 831 (1995)) (“[A]n agency’s allocation of funds from a lump-sum appropriation requires ‘a complicated balancing of a number of factors which are peculiarly within its own expertise’: whether its ‘resources are best spent’ on one program or another; whether it ‘is likely to succeed’ in fulfilling its statutory mandate; whether a particular program ‘best fits the agency’s overall policies’; and, ‘indeed, whether the agency has enough resources’ to fund a program ‘at all.’”).

Thus, BPA’s budget recommendations from IPR do not become “final” with the final rate determinations. As described above in Issue 4.2.2, ratemaking is designed to recover projected or estimated costs. Recovering these projected costs in rates does not, indeed *could not*, implement actions or expenditures (whether for fish and wildlife or other programmatic initiatives) that invariably require further planning, studies, contracting, permitting, partnership coordination, environmental compliance work, subsequent decisions or a host of other factors to actually execute.

Ninth Circuit case law confirms that BPA’s final rate determinations do not need to be accompanied by final decisions on its fish and wildlife funding. In *Golden NW*, the Court concurred with BPA that its rate case was “not the forum for making decisions regarding which fish and wildlife alternative[s] to implement . . .” 501 F.3d at 1053. Instead, what BPA must provide in its rate case (and which was lacking in *Golden NW*) is a “realistic projection of fish and wildlife costs that accurately reflected the information available at the time the rates were set and the cost recovery mechanisms adopted.” *Id.* The court acknowledged the limited and non-final nature of BPA’s funding projections that are incorporated into the rate case: they are (1) estimates that are not final and may change as programs are actually selected; and (2) based on information available at the time the rates were set, but that may change because of new facts. That is all BPA is required to include in rates and that is all BPA has done here with its projections from IPR. Moreover, just as the court in *Golden NW* found that BPA’s rates need not be based on final, reviewable funding decisions, BPA’s use of projected costs in ratemaking does not *create* final, reviewable funding decisions.

The Environmental Parties, however, contend that “as a practical matter” BPA “substantially adhere[s]” to these projections, and therefore, they must be viewed as “final.” Environmental Parties Br., BP-22-B-ID-01, at 19–20. While BPA certainly may attempt to operate within its projections, those attempts in no way make its projections any more final. Indeed, to the extent BPA’s actual ability to achieve its projections is a measure of the “finality” of its funding recommendations, the record would strongly suggest that BPA’s projections are anything but binding. Consider BPA’s transmission capital budget. As noted by several parties in the rate proceeding, BPA’s projected IPR budgets for transmission capital spending exceeded the actual execution of transmission projects over

several rate periods. *See, e.g., Kester et al.*, BP-22-E-JP03-01, at 12; Arthur, BP-22-E-MS-01, at 26–27, 31. BPA acknowledges this gap as well: “BPA acknowledges that actual capital spending historically has been lower than what has been forecast in the Capital in Review or IPR processes.” Fredrickson *et al.*, BP-22-E-BPA-36, at 31. In each prior rate period, BPA developed a projection of its expected capital programs in IPR. Nonetheless, for a variety of reasons, those projections did not match actual expenditures. This gap exists because BPA did not decide in IPR or the final rate decision which transmission projects it would pursue during the rate period. The IPR projection was only an estimate of the funding needs for the next rate period; that estimate could, of course, change for any number of reasons.

Furthermore, while BPA’s cost estimates are based upon existing or anticipated obligations, they do not create such obligations nor do they have any binding legal effect on those obligations. Said another way, BPA’s inclusion of a program in its forecast of costs for rate purposes in no way decides that such program will be pursued. Similarly, if a cost item was not included in BPA’s projected funding levels, that omission in no way prohibits BPA from funding that particular measure during the rate period. To that end, the rate case contains no findings of exactly which programs and projects will be funded by the revenues recovered in rates, a point the Environmental Parties readily acknowledge. *See Environmental Parties Br.*, BP-22-B-ID-01, at 22 (“BPA need not and should not decide during this rate case what specific measures should receive additional funding, and it need not even decide at this time what precise amount of funding is needed to satisfy its ‘equitable treatment’ obligation.”). BPA’s funding projections are general in nature to reflect the reality that BPA is not finally deciding what programs to pursue or how it will meet its various obligations over the rate period. That flexibility is needed to enable the Administrator to adjust his spending levels as projects are delayed, postponed or canceled, priorities shift, or to respond to new projects or obligations. BPA builds into rate projections certain allowances for these fluctuations, and has robust risk mechanisms to manage large changes in spending and revenues. *See Mandell et al.*, BP-22-E-BPA-46, at 7, 9-10 (identifying six risk mitigation features available to ensure BPA recovers its costs).

In summary, BPA’s projections of its funding for fish and wildlife in the IPR process is not “the consummation of the agency’s decision making” on the level of funding for fish and wildlife. As explained above, they are estimates that are subject to change. For ratemaking purposes, the IPR process provides an estimate of costs “to assume in establishing new power and transmission rates,” based on realistic projections using the best available information at the time rates are set. IPR Closeout Report, BP-22-M-ID-02-AT04, at 13; *see Golden NW*, 501 F.3d at 1053. The Environmental Parties attempt to recast the IPR process as more than budget recommendations is both factually and legally misplaced. Furthermore, applying the same logic discussed in Issues 4.2.2 and 4.2.3, inclusion of these projections in the final rates determinations does not convert these recommendations into final decisions that must be reviewed under “equitable treatment” or any other fish and wildlife requirements of the Northwest Power Act. Neither the Strategic Plan nor the IPR are final or reviewable BPA decisions, and nothing BPA has decided in this rate case has converted them into such decisions.

In their Brief on Exceptions, the Environmental Parties argue that BPA has “utterly misunderstood” their argument. Environmental Parties Br. Ex., BP-22-R-ID-01, at 29. The Environmental Parties contend that they are not asserting that IPR or the Strategic Plan are final actions or become so with the final rate determination. *Id.* at 30. Instead, the Environmental Parties contend “the point made by the Environmental Parties is that the Strategic Plan and IPR process are reviewable as part of the review of BPA’s final rate determination insofar as they fed into that rate determination.” *Id.* But this argument remains unpersuasive.

It is clear from the Environmental Parties’ briefs that they seek to challenge the underlying rationale that BPA used in developing its proposal for the BP-22 rate period. As they explain: “BPA at some point made a decision to hold fish and wildlife funding levels flat during the BP-22 rate period, and that decision – though non-final at the time it was made – is reviewable as part of the review of the final rate determination.” *Id.* at 31 (emphasis omitted). This description shows that their challenge is not to the substance of the evidence informing the projections for the BP-22 rate period, which is contained in the various rate studies included in the BP-22 record. Rather, the essence of Environmental Parties’ complaint lies with alleged intermediate “decisions” behind the projections BPA is using in this rate case. *See Confederated Tribes*, 342 F.3d at 929 (expressing suspicion as to the true nature of petitioners’ challenge and whether it amounted to challenge of earlier decisions). The Environmental Parties contend BPA’s funding decision (and the incremental decisions leading to those projections) must be reviewable because “otherwise, BPA would be able to completely insulate its programmatic funding decisions from ‘equitable treatment’ scrutiny simply by making those decisions in non-final forums – precisely what [the Administrative Procedure Act] § 704 is meant to keep agencies from doing.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 15.

The flaw in the Environmental Parties’ argument is that it presumes *all* agency inputs to the ratesetting process are reviewable.²⁹ The Environmental Parties are correct that under the Administrative Procedure Act “[a] preliminary, procedural, or intermediate agency action or ruling not directly reviewable is subject to review on the review of the final agency action.” 5 U.S.C. § 704. However, Section 704 *presumes* that the “preliminary, procedural, or intermediate” agency action or rule *is* reviewable at some point, though not *directly* reviewable when first made. This is where the Environmental Parties’ argument fails. BPA’s Strategic Plan and fish and wildlife cost projections in the IPRs are not independently

²⁹ In an effort to *find* a forum to review BPA’s funding decisions, the Environmental Parties contend that the rate case is an “appropriate occasion” to raise BPA’s compliance with “equitable treatment” for fish and wildlife funding because it covers the rate period as opposed to “shorter time periods.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 20. Even if the equitable treatment requirement applied to BPA fish and wildlife funding decisions, which BPA strongly disputes, there is no reason that “equitable treatment” would need to be shown in BPA’s rate cases as part of the final rate determination. BPA has discretion to demonstrate equitable treatment in a manner that allows for meaningful review. *See Confederated Tribes*, 342 F.3d at 931-32.

reviewable decisions and they do not become reviewable as part of the final BP-22 ratesetting action.

Courts “have long recognized that the term [agency action] is not so all-encompassing as to authorize [them] to exercise ‘judicial review over everything done by an administrative agency.’” *Indep. Equip. Dealers Ass’n v. EPA*, 372 F.3d 420, 427 (D.C. Cir. 2004) (quoting *Hearst Radio, Inc. v. FCC*, 167 F.2d 255, 277 (D.C. Cir. 1948)). They have expressly recognized several types of pre-decisional steps taken by an agency in anticipation of agency action that are not reviewable, even under the umbrella of a final decision. *See Fund for Animals, Inc. v. U.S. Bureau of Land Mgmt.*, 460 F.3d 13, 19-20 (D.C. Cir. 2006). For example: preparing proposals, conducting studies, consulting with interested parties, making budget requests, and other such activities “that comprise the common business of managing government programs” are well beyond the scope of judicial review. *Id.* at 20. Importantly, while expenditure assessments and budget proposals “may serve as [] useful planning document[s],” they do not fall within the scope of § 704. *Id.* For example, when analyzing whether the Bureau of Land Management’s Budget Initiative to request additional funding for the Wild Horse and Burro Program was reviewable, the court concluded that “[t]he individual roundups might qualify; the Bureau’s budget proposal does not.” *Id.* The court explained:

Judicial review of such budget initiatives would wreak havoc with the normal operations of agencies and the executive branch. Agencies propose all kinds of programs in the budget process, and they are not the only actors in that process. The President decides which agency budget requests to forward to Congress.

Id. at 20 (citing *Judicial Watch v. Dep’t of Energy*, 412 F.3d 125, 129-30 (D.C. Cir. 2005)).

BPA’s proposed programmatic spending levels in IPR are just that: planned spending levels used to inform BPA’s budget proposal, where BPA is not the only actor in the process.

Moreover, BPA has flexibility in developing spending projections like other Federal agencies, and its budget is ultimately determined by Congress. As explained earlier, it is well established that “[an] agency’s proposal to Congress, developed to secure the funds, may serve as a useful planning document, but it is not a ‘rule’ – that is, ‘an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy.’” *Id.* (citing 5 U.S.C. § 551(4); *Indep. Equip. Dealers Ass’n*, 372 F.3d at 428). BPA acknowledges that its IPR process, wherein it shares its funding projections with stakeholders, is uniquely transparent for a Federal agency. But simply because BPA engages in that informal process, and uses those projections to recover the costs of the Federal investment, does not somehow create a new line of law that takes non-reviewable budget submissions of a Federal agency and converts them into reviewable “interim” agency decisions that become part of the final rate determination.

The Environmental Parties rely on three cases in support of the idea that BPA’s Strategic Plan and IPR projections must be reviewable at the time of a final rate determination: *Jama v. Dep’t of Homeland Sec.*, 760 F.3d 490, 497 (6th Cir. 2014); *Ohio Forestry Ass’n, Inc. v.*

Sierra Club, 523 U.S. 726, 734 (1998); *Indus. Customers of Nw. Utils. v. Bonneville Power Admin.*, 408 F.3d 638, 645–47 (9th Cir. 2005) (hereinafter *ICNU*). From here, they claim that the intermediate decisions that led to BPA’s projections are reviewable even though they were “non-final decisions leading up to the rate case . . .” Environmental Parties Br. Ex., BP-22-R-ID-01, at 14.

The *Jama* case is distinguishable because an intermediate determination in an immigration adjudication designed to ensure due process and individuals’ rights is not analogous to the vastly different scenario at issue here – broad policy objectives described in the Strategic Plan and budget submittals prepared in the IPR process to provide the public with transparency regarding projected agency spending levels.

The *Ohio Forestry* case supports BPA’s position rather than the Environmental Parties’ position, insofar as the Environmental Parties can point to no concrete injury that they will suffer based on BPA’s use of IPR spending levels as projections in rates, or indeed from what the rates ultimately established. In *Ohio Forestry*, the U.S. Supreme Court dismissed challenges to principles established in an overall forest management plan because the Sierra Club could not demonstrate an injury because no implementation of the plan had occurred. The Court acknowledged that challenges to the plan may be appropriate when the plan was implemented and if there was concrete injury stemming from the Plan, such as when a permit approval authorized the cutting of trees or a decision closed a section of forest to certain activities. The Sierra Club had generally alleged that the plan made “logging more likely in that it [was] a logging precondition.” The Court rejected this alleged injury because the plan “[did] not give anyone a legal right to cut trees, nor [did] it abolish anyone’s legal authority to object to trees being cut.” 523 U.S. at 730, 733. Similarly, BPA’s Strategic Plan announced overall general policy direction and goals for all the agency’s programs, and the IPR planning budgets did not guarantee or disallow any actual implementation of particular actions.

Like the Sierra Club in *Ohio Forestry*, the Environmental Parties cannot point to any specific injury resulting from the use of IPR funding projections in the ratesetting process, or their incorporation in rates. Instead, they rely on generalized assertions that an increase in BPA funding of fish and wildlife mitigation and enhancement activities is warranted because the current projections “threaten[] to negatively affect fish.” Environmental Parties Br. Ex., BP-22-R-ID-01, at 15. More on point here, like the complainants in *Fund for Animals*, the Environmental Parties are also unable to demonstrate a cognizable injury based on proposed agency funding levels. As the court in *Fund for Animals* explained, “[w]hen the Bureau sought funding from Congress, it did not harm or affect the plaintiffs in this case; and they were not harmed or affected when Congress appropriated the \$9 million.” 460 F.3d at 20. Indeed, the court observed that, “there is ‘considerable legal distance’ between the appropriation of funds to implement a gather ‘strategy’ and the actual removal of wild horses and burros.” *Id.* at 22 (citing *Ohio Forestry Ass’n*, 523 U.S. at 730). As discussed above in Section 4.2.2, the Environmental Parties cannot demonstrate a concrete injury based on alleged significant impacts to fish and wildlife that could be caused by the use of IPR planning budgets in the ratesetting process, or which could be caused by the rates themselves. The Environmental Parties attempt to establish such an injury by

pointing to mitigation measures that the agency could adopt in forums where actions that more directly affect fish populations in the river have been decided. See *Environmental Parties Br. Ex.*, BP-22-R-ID-01, at 15-16.

Finally, in *ICNU*, the Court found that challenges to BPA's implementation of the Safety-Net Cost Recovery Adjustment Clause (SN CRAC) were premature until FERC had reviewed and approved BPA's final rates. In *ICNU*, customers could not establish injury from the application of adjusted rates as a result of the SN CRAC because the rates had not yet been finalized. The court explained that although the SN CRAC was a "predicate act for rate readjustment, the trigger determination itself has no final consequences." 408 F.3d at 647. The court dismissed the case for lack of jurisdiction because FERC had not provided final approval for rates. *Id.* Contrary to the Environmental Parties' reading (*Environmental Parties Br. Ex.*, BP-22-R-ID-01, at 14), the case stands for the sole proposition that BPA rates must be approved by FERC before they are challengeable as "final agency actions." *Id.* at 644. The Ninth Circuit did not "reach a decision on any other issue raised by the parties," including whether the SN CRAC determination would be reviewable as part of a final rate determination. *Id.* at 647.

Ninth Circuit jurisprudence already supports the distinction in the context of BPA's fish and wildlife expenditures as inputs to the rate case rather than decisions available for judicial review as part of a final rate determination. In *Golden NW*, the court treated BPA's fish and wildlife cost projections as "facts" that the agency relied on to make its final decision, rather than any kind of "preliminary, procedural, or intermediate agency action or ruling" by itself. 501 F.3d at 1052; 5 U.S.C. § 704.

The Environmental Parties also try to show that the final effect of BPA's decision to hold its fish and wildlife funding at or below inflation is supported by its actual practice. *Environmental Parties Br. Ex.*, BP-22-R-ID-01, at 18-20, 32. The Environmental Parties present tables comparing BPA's fish and wildlife funding projections and its actual spending. *Id.* at 19-20. Two points can be drawn from these charts. First, one table shows BPA frequently manages its budgets within its projections. (Indeed, it would be cause for concern were that not the case.) Among its many statutory duties, BPA is required to operate consistent with sound business principles. See 16 U.S.C. § 839e(a)(1); *Pac. Nw. Generating Co-op. v. Bonneville Power Admin.*, 596 F.3d 1065, 1073 (9th Cir. 2010). Planning budgets based on known commitments and obligations, and then adhering to this, reflects a sound business practice. Showing that BPA routinely spends within its projected budget is unremarkable and hardly cause for throwing out current budget projections and starting anew.

Second, the evidence presented in the Environmental Parties' arguments support BPA's original point – that BPA's projections do not establish how much BPA will actually spend on fish and wildlife. In all of the charts provided by the Environmental Parties, BPA's spending is lower than the projections. In one sense, then, BPA has consistently *overstated* its projected fish and wildlife spending to ensure that adequate funding is available. As BPA has maintained all along, decisions outside of the rate case decide which programs to pursue, which to postpone, and ultimately which to commit BPA funds to fish and wildlife.

The Environmental Parties' tables show that BPA's view is the correct one. The actual funding of programs is where the decisions are made; not in the general projections for ratemaking.

Moreover, if the Environmental Parties were correct that *any* input into a ratemaking decision becomes reviewable with the final rate determination, there would be virtually *no* issue, decision, policy, contract, or action that would fall outside of BPA's rate determinations. BPA must recover its "total system costs," 16 U.S.C. § 839e(a)(2)(B), in rates and, as such, virtually everything BPA does can in some way be traced to an assumption used in ratemaking. Administering the Northwest Power Act Section 7(i) rate case for the areas identified by Congress in Section 7 is already complex enough. Turning the final rate determination into a referendum on every underlying policy, statement, or position that "fed into" that decision would make the rate proceeding an unworkable, jumbled administrative nightmare. Mercifully, there is no indication in Section 7 or any other law that BPA must go here. All that BPA must decide in its final rate determinations is how to recover its cost obligations with appropriate allocation across ratepayer classes in accordance with the requirements of Section 7, which BPA has done.

In summary, the non-final policy goals of the Strategic Plan and the projections developed in IPR are not reviewable. Further, as mentioned in Issue 4.2.2, since these documents are non-reviewable, they similarly cannot form the basis of an alleged "string of decisions" that culminate in a "significant impact" on fish and wildlife as part of the final rate determination, as contended by the Environmental Parties.

Decision

BPA's policy objectives outlined in the Strategic Plan and cost projections from the Integrated Program Review processes do not become reviewable decisions when BPA issues its final rate determinations.

Issue 4.2.5

Whether BPA should reject the Settlement and agree to the Environmental Parties' requested action to commit a "substantial portion" of the projected net secondary revenue increase to fish and wildlife funding.

Parties' Positions

The Environmental Parties argue that the Administrator "should reject the Settlement Proposal and commit to increased funding for measures to protect, mitigate, and enhance fish and wildlife." Environmental Parties Br., BP-22-B-ID-01, at 22. Or, in an alternative, the Environmental Parties contend BPA should devote a "substantial portion" of the projected increase in net secondary revenue to fund fish and wildlife programs. *Id.* at 3, 10, 15, 17, 22. In its Brief on Exceptions, the Environmental Parties reiterate their position that the settlement must be rejected, but add that they are not requesting specific outcomes, but have identified "procedural" errors BPA must correct before proceeding with its final rate determinations. Environmental Parties Br. Ex., BP-22-R-ID-01, at 32-34.

BPA Staff's Position

BPA fish and wildlife funding projections are not decided in BPA's ratemaking proceedings, but are evaluated in other processes, such as IPR. Mandell *et al.*, BP-22-E-BPA-46, at 3. Nevertheless, BPA's funding projections for its fish and wildlife projects have been reviewed and are based on the best available information. *Id.*; see also IPR 2 Closeout Report at 4, 11.

Evaluation of Positions

The Environmental Parties propose a remedy for perceived defects in BPA's legal compliance through this rate case. In doing so, the Environmental Parties assert that the "unexpected surge in surplus revenue [gives] BPA a 'unique' opportunity to shore up its financial position through revenue financing, [and] also presents an opportunity for fish and wildlife. BPA has a statutory duty to take advantage of that opportunity." Environmental Parties Br., BP-22-B-ID-01, at 16. Paradoxically, elsewhere in their brief, the Environmental Parties concede that "BPA has discretion to use surplus revenue for various purposes, including bolstering its financial health." *Id.* at 13. By not considering using the projected increase in revenue for additional fish and wildlife funding, the Environmental Parties contend BPA is violating the Administrative Procedure Act and ignoring an "important aspect" of the decision before it. *Id.*; see also *id.* at 8.

BPA has already addressed above the reasons it does not, as a matter of law, have an obligation to revisit its fish and wildlife funding projections in this case under equitable treatment or other provisions of the Northwest Power Act. That discussion also applies to BPA's decision to adopt the Settlement discussed in Section 2 of this Final ROD.

More generally, BPA understands the Environmental Parties position as asserting that, even if BPA does not have a legal obligation under the Northwest Power Act to reconsider its fish and wildlife projections, BPA nonetheless should have reassessed those funding levels before adopting the Settlement. To that end, the Environmental Parties oppose the Settlement because it allegedly forecloses other uses for the projected increase in revenue, such as increased projected fish and wildlife funding. See Environmental Parties Br., BP-22-B-ID-01, at 2 ("Whether or not the Settlement Proposal represents a fair compromise between BPA and its customers, it is a compromise that is fundamentally unfair to fish and wildlife."). The Environmental Parties contend BPA can remedy this error by allocating a "substantial portion" of that increase to its fish and wildlife budgets, instead of reserving it all for its customers and future revenue financing. *Id.* at 3, 10, 15, 17.

BPA's proposal for the use of the projected increase in net secondary revenue for the BP-22 rate period, as embodied in the Settlement, is a reasonable and sound business decision that is supported by the record in this case.

First, it is important to understand the nature of the "increase" discussed in BPA's testimony and cited by the Environmental Parties. BPA Staff explained the unique situation it faced in this case was a *projected* increase in net secondary revenue for the BP-22 rate period that could result in a 4.5 percent rate decrease. Fisher *et al.*, BP-22-E-BPA-15, at 2. A large portion of this reduction was fueled by a \$100 million projected increase in revenue

from BPA's net secondary sales, which amounted to a 40 percent increase over the BP-20 forecast. Fisher *et al.*, BP-22-E-BPA-35, at 21. BPA's net secondary sales are a source of great uncertainty and risk in BPA rate forecasts. Large swings in BPA's net secondary sales are common, with the standard deviation varying between \$125 million and \$180 million. *Id.* at 22. Over the past 13 years, BPA has missed its net secondary sales forecast in eight of 13 years. *Id.* In five of those years, actual net secondary sales revenue came in at more than \$100 million *below* projections. *Id.* Those missed projections were offset by BPA through reductions in its financial reserves, requiring BPA to take concerted action to rebuild those reserves. *Id.* at 22. Faced now with a 40 percent increase in what has historically been BPA's largest source of volatility and uncertainty, BPA Staff understandably expressed "caution" with proposing to set rates assuming these increases were certain. *Id.* Thus, BPA Staff looked for other ways to manage this risk while also accounting for these higher projections in its rates.

The proposed solution adopted in the rate case as part of the Settlement was to allow the BP-22 power rates to decline slightly, and use up to \$40 million of the projected net secondary revenue increase to reduce debt issuance through revenue financing. *See* Issue 4.2.2; *see also* Appendix A (Settlement), Attachment 1, § 1.a. Revenue financing simply means paying with current revenues a cost that could otherwise be paid for with long-term debt. Fisher *et al.*, BP-22-E-BPA-15, at 6. BPA identified many benefits of this approach, including reducing borrowing costs, preserving scarce federal borrowing authority, de-leveraging BPA's power business, rate stability, and supporting the agency's credit rating. *See id.* at 8-13; Fisher *et al.*, BP-22-E-BPA-35, at 4. Importantly, this proposal is a *conditional* use of the projected increase in revenues for revenue financing. Fisher *et al.*, BP-22-E-BPA-35, at 22-23. That is, for rate setting, BPA would presume to use \$40 million of the projected net secondary revenue increase for revenue financing, but only to the extent BPA believed it could do so without causing a decline in Power's financial reserves for risk relative to the start of the rate period. *Id.* This approach effectively converts the \$40 million in revenue financing into a liquidity preservation tool that would be employed to fill gaps if and when BPA's projected costs (including cost projections from fish and wildlife funding obligations) or net revenues deviate from forecasts and impact financial reserve levels. *Id.* The Settlement's proposed revenue financing mechanism provides unprecedented risk mitigation for both BPA's costs (including its fish and wildlife costs) and revenues, and therefore, is an eminently sound business decision.

The Environmental Parties contend in their brief that BPA's proposed use of its increase in net secondary revenue presents a binary outcome, in which BPA's customers win and its fish and wildlife interests lose. *See* Environmental Parties Br., BP-22-B-ID-01, at 9 ("rather than going back and reconsidering fish and wildlife spending levels in light of changed circumstances, BPA's Initial Proposal completely ignored the agency's "equitable treatment" obligation, instead treating future net secondary surplus revenues as a pot of money to be used solely for non-fish purposes."). That is inaccurate as the risk mitigation benefits of the Settlement extend to all of BPA's programs, including BPA's fish and wildlife program. Specifically, by protecting BPA cash reserves, BPA is strengthening its ability to pay for fish and wildlife costs that may come in above projected amounts. *See* Issue 4.2.2,

where BPA's risk mitigation measures are discussed. In addition, many of the fish and wildlife programs are part of BPA's capital budget, meaning that BPA generally will consume borrowing authority to finance these costs. *See, e.g., Mandell et al., BP-22-E-BPA-46, at 3.* Taking actions now to preserve that borrowing authority is a step towards ensuring that BPA can continue to fund its capital programs, including applicable fish and wildlife programs, using cost-effective financing for years to come. In these ways, the Settlement is not divvying up the projected net secondary revenue as a "pot of money to be used solely for non-fish purposes." *See Environmental Parties Br., BP-22-B-ID-01, at 9.* Instead, the Settlement provides broad financial benefits that support BPA's ability to meet its statutory obligations, including its obligations to fund fish and wildlife actions.

Finally, BPA finds unpersuasive the Environmental Parties' argument that BPA should reject the Settlement because it did not take into account the Environmental Parties' alternative funding proposals. The Settlement that BPA proposes to adopt ends significant controversy in the rate case and provides real, tangible benefits through near-term rate relief, support for BPA's rate period cost recovery, and benefits to BPA's long-term financial health. *See Section 2.* The Settlement provides these benefits through specific actions BPA takes in its final rate determinations. *See Section 2; see also Appendix A (Settlement), Attachment 1.*

The specificity of the Settlement and its associated benefits stand in stark contrast to the vague and indefinite requests of the Environmental Parties. Throughout its brief, the Environmental Parties demand that BPA commit additional funds for fish and wildlife: "BPA must . . . commit[] a substantial portion of incremental revenue . . . to improve implementation of fish protection, mitigation, and enhancement measures." *Environmental Parties Br., BP-22-B-ID-01, at 10; see also id. at 15* (noting BPA should "boost funding for measures to 'protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by' the Federal Columbia River Power System"); *id. at 22* ("[T]he Administrator should reject the Settlement Proposal and commit to increased funding for measures to protect, mitigate, and enhance fish and wildlife."). The Environmental Parties never identify what additional amount BPA must commit. *See id.* Indeed, the Environmental Parties contend that BPA does not need to decide in its final ratemaking decision what amounts are needed to meet its obligations. *See id. at 22* ("BPA need not and should not decide during this rate case what specific measures should receive additional funding, and it need not even decide at this time what precise amount of funding is needed to satisfy its "equitable treatment" obligation."). Nor have they presented any evidence on the record demonstrating that BPA's funding projection will not meet its fish and wildlife obligations. In the end, BPA is left with the ambiguous request that it reject a broadly supported and principled rate settlement in order to "increase funding" for fish and wildlife to some indefinite level.

Weighing these alternatives, BPA finds that there can be little question that adoption of the Settlement is reasonable and a proper exercise of its ratemaking discretion. In choosing to adopt the Settlement, BPA is guided by the requirement that its decision must not be arbitrary, capricious, an abuse of discretion or otherwise not consistent with the law, *see S. Cal. Edison v. Jura, 909 F.2d 339, 342 (9th Cir. 1990)*, and must be supported by evidence

in the ratemaking record. *See* 16 U.S.C. § 839f(e)(2); *see also Cent. Lincoln Peoples' Util. Dist.*, 735 F.2d at 1116. BPA's ratemaking decision must also be made in accordance with "sound business principles." 16 U.S.C. § 839e(a)(1); *see also Public Power Council, Inc., v. Bonneville Power Admin.*, 442 F.3d 1204, 1206 (9th Cir. 2006). BPA finds that its decision to adopt the Settlement, with the immediate near-term and long-term benefits described above, soundly meet these requirements. Further, BPA has considered the Environmental Parties' concerns about equitable treatment, additional funding for Council fish and wildlife programs, the Administrative Procedure Act, as well as their request that BPA, as a matter of its discretion, include an indefinite amount of additional funding for fish and wildlife, and concludes that none of these objections persuade BPA that its decision here is unreasonable or contrary to law.

In its Brief on Exceptions, the Environmental Parties reiterate many of the arguments they make above to support their view that, under the Northwest Power Act and the Administrative Procedure Act, BPA must reject the settlement. Environmental Parties Br. Ex., BP-22-R-ID-01, at 32-33. In addition, though, they now also contend that these errors are "procedural" in nature, and that the flaw in BPA's decision is not in the ultimate "outcome" BPA must reach, but that BPA must "fulfill" these obligations to make a lawful rate determination. *Id.* at 33.

BPA disagrees that the final rate determination, and its decision to adopt the settlement, must be rejected because of alleged procedural violations stemming from the Northwest Power Act and the Administrative Procedure Act. As BPA has explained above, BPA has met all of the requirements prescribed by the Northwest Power Act and the Court to set rates to recover its costs – a point the Environmental Parties have failed to refute. BPA has already explained above what procedures Congress prescribed for BPA to set rates, and those procedures do not include conducting independent analysis in its final rate determinations of either Section 4(h)(11)(A)(i) or (ii). *See* Issues 4.2.1, 4.2.2.

The Environmental Parties' arguments become no more persuasive by recasting them as "procedural." Article III standing criteria³⁰ bear no relevance here. Nor does standing doctrine replace the Ninth Circuit's standard for considering when BPA has to demonstrate whether its actions provided equitable treatment to fish and wildlife: "when BPA makes a final decision that significantly impacts fish and wildlife." *Confederated Tribes*, 342 F.3d at 931. Environmental Parties suggest that they met this standard by presuming that "compliance with the procedural requirements of § 4(h)(11)(A)(ii) *could* lead BPA to increase funding for fish and wildlife mitigation . . . and that such increased funding *could* benefit fish and wildlife." Environmental Parties Br. Ex., BP-22-R-ID-01, at 27-28. This, however, is not a test of Environmental Parties' standing to sue. It is a formal ratemaking process evaluating whether BPA is basing its proposed rates on "substantial evidence." Two "coulds" and a "presumed" do not amount to evidence substantial enough to warrant BPA revisiting its proposed rates.

³⁰ Environmental Parties Br. Ex., BP-22-R-ID-01, at n.112.

The Environmental Parties' procedural argument amounts to an attempt to create a new threshold for litigating Section 4(h)(11)(A) issues because they could not meet the existing standard stated in the plain language of the statute and Ninth Circuit jurisprudence, as explained throughout this chapter. Unable to provide substantial evidence of BPA having triggered that standard, they proffer another – one without any basis whatsoever in the statute itself. For these and the reasons reiterated throughout this Final ROD, BPA rejects the Environmental Parties' procedural argument.

BPA's decision to adopt the settlement as part of the final rate determination is a sound decision, supported by the administrative record, and in accordance with the requirements of the Northwest Power Act and applicable law.

Decision

BPA's decision to adopt the Settlement is a reasonable exercise of BPA's ratemaking discretion. The Settlement ends substantial controversy in the rate proceeding, provides near-term rate relief to its customers, strengthens BPA's cost recovery over the rate period (including cost recovery for BPA's fish and wildlife funding), and supports BPA's long-term financial health. Furthermore, BPA's decision to not revise or otherwise commit a "substantial portion" of the projected net secondary revenue increase to fish and wildlife funding is supportable and sound.

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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 who comment on BPA's rate proposal but do not take part in the formal hearing process with the responsibilities of "parties." Rules of Procedure § 1010.8(a)–(c). Parties to the case file testimony and briefs and are not allowed to submit comments as participants. *Id.* § 1010.8(d). Participant comments are part of the official record of the rate proceeding and are considered when the Administrator makes his final decisions.

As described in section 1, the Federal Register notice for this proceeding set a deadline of March 1, 2021, for participant comments. 85 Fed. Reg. 77,189, 77,193 (Dec. 1, 2020). BPA received four comments through the participant comment process. A summary of each of the participant comments, and BPA's responses, are provided below.

Comment BP22200001 – Charles Pace. Participant Pace commented: "Section 839e(i)(2) of the Northwest Power Act requires that expeditious hearings be conducted 'to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and related arguments.['] Subsection (A) requires 'in any hearing . . . any person shall be provided an adequate opportunity . . . to offer refutation or rebuttal of any material submitted by any other person or the Administrator. Thus, the statutory language requires all PERSONS be allowed opportunity to participate in refutation and rebuttal. The [BP-22] rate case schedules established by the administrative hearing officer for both transmission proceeding and power proceedings exclude persons who are 'participants' – not just 'parties' – to offer refutation and rebuttal. Put somewhat differently, the schedules established for the rate proceedings are not in accord with the requirements of law. The fact that BPA has routinely violated section 839e(i)(2) in past hearings going back to at least the advent of 'tiered rates' makes it no less unlawful. In fact, I'd argue BPA's longstanding violations of law make it absolutely imperative that this practice, which excludes participants from refutation and rebuttal by the express provisions of the scheduling order, be discontinued."

Response to Comment BP22200001. Participant Pace suggests that the participant comment deadline does not provide participants with an opportunity to offer refutation and rebuttal and is therefore contrary to the Northwest Power Act. The Act provides the public an opportunity to submit comments related to the proposed rates. 16 U.S.C. § 839e(i). The Administrator has discretion to create the procedural rules for proceedings conducted pursuant to Section 7(i) of the Act.

BPA's Rules of Procedure provide all persons with the opportunity to provide comments as either a "party" or a "participant." Persons wishing to participate in the evidentiary hearing (*e.g.*, to submit direct and rebuttal testimony) and conduct cross examination may petition to intervene as a party. *See* Rules of Procedure § 1010.6. Persons wishing to submit comments without being subject to the duties of a party may submit comments as a participant. *Id.* § 1010.8.

The procedural schedule set the date for participant comments on March 1, 2021, which allowed participants the opportunity to submit comments after all issues had been identified by the litigants in the formal hearing; that is, after BPA filed its Initial Proposal and the parties filed their direct cases (the direct cases respond to BPA's proposal and include any additional affirmative arguments). BPA did not receive any requests to extend the participant comment deadline.

Comment BP22200002 – Scott Coe, Emerald PUD. Participant Coe characterizes the power revenue financing proposal as disturbing and disappointing in that BPA appears to be taking unilateral steps to avoid passing rate benefits on to its customers. Mr. Coe argues that a “revenue financing” charge is not cost-based and should be disallowed in the current rate proceedings. He also maintains that the power revenue financing proposal is the second time recently that BPA has driven up the price of the Regional Dialogue contract products with a non-cost-based pricing component; the first was BPA's Financial Reserves Policy two years ago. Mr. Coe asserts that these two items are not costs, but instead concern financial goals which should have been part of the Regional Dialogue contract agreement. Mr. Coe also questions what might happen if the proposal is adopted and higher net secondary revenues fail to materialize as projected.

Mr. Coe states that it appears that BPA feels it is better equipped to manage customers' dollars and that individual utilities cannot be trusted to make sound investments at the local level. He also argues that this proposal will impact public power's decision-making when it comes to post-2028 contracts.

Response to Comment BP22200002. Chapter 2 of this Final ROD explains that the Administrator is adopting a Settlement that addresses the final proposed rates as well as BPA's agreement to hold workshops on certain topics prior to the BP-24 rate case. The power revenue financing proposal is addressed in the Settlement, and has been reduced from \$95 million per year to \$40 million per year. Settlement, Attachment 1, § 1.a. The Settlement also provides that the average PF Tier 1 effective rate will decrease by up to 2.5 percent depending on the forecast of net secondary revenue. *Id.* Likewise, the public workshops on financial issues that BPA will hold are specified in the Settlement. *Id.* § 1.c. The issues and concerns raised by Mr. Coe can be discussed at these workshops.

PNGC raised a similar concern with regard to the Regional Dialogue (RD) contract agreement. Gray & Mendonca, BP-22-E-PN-01, at 8–10. Staff addressed this concern in its rebuttal testimony where it explained that neither the RD contracts nor the Tiered Rate Methodology (TRM) constrains BPA's ability to either (1) change the way it finances its capital assets, or (2) manage its financial risk. Fisher *et al.*, BP-22-E-BPA-35, at 37-42.

Please note that BPA's Initial Proposal was to forgo revenue financing to the extent that Power financial reserves were expected to decrease for any reason, including net secondary revenue that did not materialize as forecast, relative to start-of-rate-period levels. Staff provided this clarification of its intent in its rebuttal testimony. *Id.* at 19-20.

Comment BP22200003 – Lukas. Participant Lukas stated that the proposed use of \$95 million for revenue financing of capital programs is unacceptable and should be withdrawn. Mr. Lukas states that BPA surprised its customers with an ill-conceived

proposal to replace badly needed rate relief with an effort to cross-subsidize business unit capital activity. Mr. Lukas states that BPA has done little to address long-term access to capital challenges besides seeking more money from its customers. Mr. Lukas believes that the revenue financing proposal violates both the spirit and intent of BPA's contractual obligations to customers to provide power at cost, which includes a net secondary sales credit.

Response to Comment BP22200003. As described in response to the previous comment, the Settlement reduces the amount of proposed power revenue financing to \$40 million per year and provides that the average PF Tier 1 effective rate will decrease by up to 2.5 percent depending on the forecast of net secondary revenue. Staff's testimony in this proceeding fully explained the reasons for revenue financing in power rates, and the workshops that BPA has committed to conduct after the BP-22 proceeding will provide a forum for the discussions related to BPA's financial health objectives, including sustainable debt management and capital funding approaches, which will include discussions regarding future revenue financing and borrowing authority issues, and other financial plan goals.

With regard to the net secondary sales credit included in rates, Staff's proposal included the full expected secondary sales credit in rates the same as it has since the beginning of the RD contracts. The issue at hand was the amount of revenue financing to include in Power rates, not the amount of the secondary sales credit to include in power rates. As stated above, neither the RD contracts nor the TRM constrain BPA's ability to either (1) change the way it finances its capital assets, or (2) manage its financial risk. Fisher *et al.*, BP-22-E-BPA-35, at 37-42.

Comment BP22200004 – Bear Prairie. Participant Prairie strongly encourages BPA to reconsider the power revenue financing proposal and “honor the spirit of the deal that was entered into.” He urges BPA to reflect the higher secondary revenue forecast in the proposed rate levels and provide the rate relief it brings after years of “extreme increases in rates due to poor secondary revenues, and increasing Agency expenses.” Mr. Prairie states that BPA needs to fulfill its contractual commitments by crediting all surplus revenue to the rates. Mr. Prairie believes that these types of actions make it troubling to sign new power sales contracts “if in the good years BPA doesn't flow the surplus back through to the customer through a rate decrease.”

Response to Comment BP22200004. As described above, the amount of power revenue financing in rates under the Settlement has been reduced to \$40 million per year, and the Settlement provides that the average PF Tier 1 effective rate will decrease by up to 2.5 percent depending on the forecast of net secondary revenue.

Also as described above, Staff's proposal included the full expected secondary sales credit in rates the same as it has since the beginning of the RD contracts. The issue at hand was the amount of revenue financing to include in Power rates, not the amount of the secondary sales credit to include in power rates. As stated above, neither the RD contracts nor the TRM constrains BPA's ability to either (1) change the way it finances its capital assets, or (2) manage its financial risk. Fisher *et al.*, BP-22-E-BPA-35, at 37-42.

Lastly, with regard to the spirit of the RD deal, this same concern was brought up by PNGC. Staff addressed this concern extensively in its rebuttal testimony. *Id.* at 36–42.

6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

Consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq.*, BPA has assessed the potential environmental effects that could result from implementation of BPA's FY 2022-2023 proposed power, transmission, and ancillary and control area service rate adjustments (BP-22). The NEPA analysis was conducted separately from the formal ratemaking process.

In the Federal Register notice for the BP-22 rate adjustment proposal, BPA provided interested parties the opportunity to submit public comments concerning potential environmental effects of the proposal, which would be considered by BPA's NEPA compliance staff in the NEPA process for the proposal, 85 Fed. Reg. 77,189, 77,193 (2020). No comments concerning NEPA compliance or potential environmental effects to consider in the NEPA process were received before the comment deadline of March 1, 2021.

The decision to adopt the proposed rate adjustments is primarily administrative, strategic and financial in nature. The rate proposal largely continues the same rate construct as in previous years, albeit at adjusted levels as described elsewhere in this Final ROD and with additional measures related to revenue financing. Provisions are also included to allocate charges and credits attributable to Bonneville's possible participation in the Western Energy Imbalance Market (EIM), should the agency decide to join the EIM. All of these aspects of the proposal involve changes to BPA's rates to ensure that there are sufficient revenues to meet BPA's financial obligations and other costs and expenses while using existing generation sources operating within normal limits. Given this, adoption of the rate proposal is not expected to result in reasonably foreseeable environmental effects.

Accordingly, BPA has determined that the BP-22 rate adjustment proposal falls within a class of actions excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this proposal falls within categorical exclusion B4.3, *Electric power marketing rate changes*, found at 10 C.F.R. § 1021, subpart D, appendix B, which provides for the categorical exclusion from further NEPA review 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." BPA has prepared a categorical exclusion determination memorandum that documents this categorical exclusion from further NEPA review, which is available at the BPA website:

<https://www.bpa.gov/efw/Analysis/CategoricalExclusions/Pages/2021.aspx>.

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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. Consistent with NEPA, BPA has evaluated the potential environmental impacts that could result from implementation of the FY 2022–2023 proposed power and transmission rate adjustments.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby establish the accompanying 2022 Power Rate Schedules and General Rate Schedule Provisions (GRSPs) and the 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs as 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 GRSPs adopted herein contain the lowest possible rates consistent with sound business principles and are consistent with other applicable laws.

Issued at Portland, Oregon, this 28th day of July, 2021.

/s/ John L. Hairston

John L. Hairston
Administrator and Chief Executive Officer

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APPENDIX A

Settlement Agreement for Rates for Fiscal Years 2022–23

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SETTLEMENT AGREEMENT FOR RATES FOR FISCAL YEARS 2022-23

Bonneville Power Administration BP-22 Rate Proceeding

This SETTLEMENT AGREEMENT (“Agreement”) is among the Bonneville Power Administration (“Bonneville”) and parties as provided for in section 3 of this Agreement (such parties in the singular, “Party,” in the plural, “Parties”).

Bonneville and the Parties agree to the following:

1. In the BP-22 Rate Proceeding (BP-22 Proceeding), Bonneville staff will file and recommend that the Administrator adopt a proposal (Settlement Proposal) consistent with this Agreement for rates for power, transmission, ancillary and control area services for Fiscal Years (FY) 2022 and 2023. The Settlement Proposal will include only the terms specified in this Agreement and in Attachment 1.
2. This Agreement settles, in accordance with its terms, all issues within the scope of the Settlement Proposal for purposes of the BP-22 Proceeding.
3. Bonneville will notify the Hearing Officer about this Agreement and move the Hearing Officer to (1) require any party in the BP-22 Proceeding that does not sign the Agreement to state any objection to the Settlement Proposal by a date established by the Hearing Officer; and (2) specify that any party in the proceeding that does not state an objection to the Settlement Proposal by such date will waive its rights to preserve any objections to the Settlement Proposal and will be deemed to assent to this Agreement.
4. If, in response to the Hearing Officer’s order made pursuant to section 3, any party to the BP-22 Proceeding states an objection to the Settlement Proposal, Bonneville and any Party to this Agreement will have two business days from the date of the objection to withdraw its assent to the Settlement Proposal. If Bonneville or any Party to this Agreement withdraws its assent to the Settlement Proposal, Bonneville shall promptly schedule a meeting with the Parties to this Agreement to discuss how to proceed and will provide notice and the opportunity to participate to parties to the BP-22 Proceeding.
5. This Agreement will terminate on September 30, 2023, except that, if the BP-22 Proceeding does not result in the adoption of this Agreement, the Agreement will be void *ab initio*.

6. Preservation of Settlement Proposal

- a. The Parties agree not to contest this Agreement in the BP-22 Proceeding, or other forum, or the implementation of this Agreement pursuant to its terms, through the end of FY 2023.
- b. The Parties agree to waive their rights to briefs and oral argument in the BP-22 Proceeding with respect to any issue within the scope of the Settlement Proposal, except in response to issues raised by any party in the proceeding that objects to this Agreement in response to the Hearing Officer's order made pursuant to section 3.
- c. Bonneville and the Parties agree that this Agreement does not constitute consent or agreement in any future Bonneville proceeding, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such matters in such proceedings.
- d. Bonneville and the Parties acknowledge that this Agreement reflects a compromise in their positions with respect to the issues within the scope of the Settlement Proposal, and that acceptance of the settlement does not create or imply any agreement with any position of any other Party. Bonneville and the Parties agree not to assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by Bonneville or any Party, the Hearing Officer, the Administrator, the Federal Energy Regulatory Commission, or a court, creates or implies: (1) agreement to any particular or individual treatment of costs, expenses, or revenues; (2) agreement to any particular interpretation of Bonneville's statutes; (3) any precedent under any contract or otherwise between Bonneville and any Party; or (4) any basis for supporting any Bonneville rate, general rate schedule provision, or term and condition of transmission service for any period after the end of FY 2023.
- e. Bonneville and the Parties agree that this Agreement establishes no precedent and that Bonneville and the Parties will not be prejudiced or bound thereby in any proceeding, except as specifically provided in this Agreement. The Parties will not be deemed to have approved, accepted, agreed or consented to any concept, theory or principle underlying or supposed to underlie any of the matters provided for in this Agreement.

7. Conduct, statements, and documents disclosed in the negotiation of this Agreement will not be admissible as evidence in the BP-22 Proceeding, any other proceeding, or any other judicial or administrative forum, nor will the fact that the Parties entered into this settlement be cited or used in any future proceedings or Administrator decisions as support for any matters, other than application or enforcement of this Agreement.

8. Reservation of rights

- a. Except as provided in section 6 above, no 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 Parties reserve the right to respond to any filings, protests, or claims by Bonneville, any Party, or others; however, the Parties will not support a challenge to any rates, terms and conditions, or other matters described in this Agreement.
 - c. No Party agrees or admits that the level of financial reserves resulting from the Transmission Rates, if any, is acceptable or otherwise appropriate, and nothing in this Agreement shall limit, waive, or otherwise alter a Party's right to challenge in future rate proceedings the level of Bonneville's financial reserves.
 - d. No Party agrees or admits that the level of revenue financing included in the Transmission Rates or Power Rates is acceptable or otherwise appropriate, and nothing in this Agreement shall limit, waive, or otherwise alter a Party's right to challenge in future rate proceedings Bonneville's inclusion of revenue financing in rates, the level of any such revenue financing, the application of depreciation to assets funded by revenue financing, or the accounting or other rate treatment of amounts included in rates for revenue financing or debt prepayment.
9. If, because of a ruling issued in response to a legal challenge, Bonneville is required to materially modify or discontinue any of the rates, terms and conditions, or other matters provided in this Agreement, Bonneville may seek, and the other Parties agree to support, or not contest, a stay of enforcement of that ruling until after the end of FY 2023.
 10. Attachment 1, Terms for Rate Issues for FY 2022-2023, is made part of this Agreement.
 11. Nothing in this Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's rates and terms and conditions of transmission service or the Parties' rights to challenge such revisions.
 12. Notwithstanding section 5 of this Agreement, sections 6, 7, and 8 will survive termination or expiration of this Agreement.
 13. This Agreement may be executed in counterparts each of which is an original and all of which, taken together, constitute one and the same instrument.

Bonneville Power Administration

Signature: SUZANNE COOPER Digitally signed by SUZANNE COOPER
Date: 2021.04.29 08:44:44 -07'00'

Signatory: Suzanne B. Cooper

Title: Senior VP, Power Services

Bonneville Power Administration

Signature: RICHARD SHAHEEN Digitally signed by RICHARD SHAHEEN
Date: 2021.04.29 07:55:24 -07'00'

Signatory: Richard L. Shaheen

Title: Senior VP, Trans. Services

Party Name: _____

Signature: _____

Signatory: _____

Title: _____

ATTACHMENTS

Attachment 1 – Terms for Rate Issues for FY 2022-2023

Attachment 1 - Terms for Rate Issues for FY 2022-2023

1. Revenue Financing

- a. Power Revenue Financing.** The amount of proposed power revenue financing will be limited to \$40 million per year. As described in Staff's testimony, such revenue financing would occur only to the extent that Power Services liquidity was not expected to be reduced from fiscal year 2022 start-of-year amounts. Planned Net Revenues for Risk would be added if the average PF Tier 1 effective rate as calculated in the final BP-22 studies would otherwise be below negative 2.5% compared to the current average BP-20 PF Tier 1 rate.
- b. Transmission Revenue Financing.** The amount of proposed transmission revenue financing will be limited to \$40 million per year. All else equal, the proposed reduction of revenue financing would have approximately a 0.5% rate decrease from the BP-22 Initial Proposal. As described in Staff's testimony, such revenue financing would occur only to the extent that Transmission Services liquidity was not expected to be reduced from fiscal year 2022 start-of-year amounts.
- c. Public Process**
 - i. In the fourth quarter of fiscal year 2021, Bonneville plans to commence public workshops as part of a "refresh" of Bonneville's 2018 Financial Plan. The refresh effort will include consideration of, among other things, Bonneville's financial health, including access-to-capital issues, sustainable capital funding approaches, long-term debt management, and other financial objectives. As part of the public process for the refresh effort, Bonneville will include discussion and consideration of issues related to Bonneville's borrowing authority and the use of revenue financing as a source of capital funding.
 - ii. Bonneville will dedicate at least one workshop prior to BP-24 to discuss the accounting and ratemaking treatment of revenue financing.

2. Transmission Losses

- a. Capacity Charge for Delayed Loss Returns.** Bonneville will not adopt a capacity charge for the delayed return of transmission losses.
- b. Financial Loss Returns.** Bonneville will adopt charges for financial returns of transmission losses consistent with Staff's Initial Proposal.
- c. Financial for Inaccuracy Penalty Charge.** Bonneville will adopt a Financial for Inaccuracy Penalty Charge consistent with Staff's Initial Proposal, as modified in Staff's Rebuttal Testimony.

- d. Public Process.** Bonneville will work toward implementing a concurrent loss-return service by the start of the BP-24 rate period or sooner, including development of an implementation plan. The implementation plan will include a timeline for engaging customers through workshops as well as opportunities for customers to provide feedback. The plan will also account for the potential need to make business practice changes according to Bonneville's Business Practice Process. Bonneville will share the implementation plan with customers no later than the end of the first quarter of FY 2022.

3. EIM Costs and Benefits

- a. Allocations.** Bonneville will implement allocations of costs and benefits associated with the Western EIM consistent with Staff's Initial Proposal.
- b. Public Process.** If Bonneville decides to join the Western EIM, Bonneville commits to hold workshops prior to the BP-24 rate case with stakeholders on how Power Services will include EIM benefits in power rates.

4. Balancing Services

- a. Ancillary and Control Area Services Balancing Service Rates - Western EIM Participation.** If Bonneville joins the Western EIM, a discount to balancing services would be provided based on the assumption of a 50% offset in hydro-shift costs and spill costs for non-regulation balancing capacity reserves as calculated through the GARD model.
- b. Dispatchable Energy Resource Balancing Service Rate.** The rate increase will be limited to 50% of the calculated impact in the Final Proposal compared to BP-20, with the excess costs allocated to other ACS rates (VERBS for Wind, VERBS for Solar, and RFR).
- c. Public Process.** Bonneville will dedicate workshops prior to BP-24 to discuss Bonneville's BP-22 balancing services methodology. Such discussion will encompass VER, DER, and load balancing services.

- 5. Transmission Utility Delivery Charge.** The rate increase will be limited to 25%, with the excess costs allocated to the Network segment (NT and PTP rates).

- 6. Eastern Intertie Public Process.** BPA will discuss and address rates and related issues regarding the Eastern Intertie in at least one pre-rate case workshop prior to the BP-24 proceeding, acknowledging the interests of the Montana Intertie parties and BPA transmission customers, and taking into account the projected long-term firm demand for the Eastern Intertie post-2025.

- 7. Other Issues.** All other issues will be addressed consistent with Staff's Initial Proposal, as modified by Staff's rebuttal testimony.

BP-22 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix B:
2022 Power Rate Schedules and
General Rate Schedule Provisions

BP-22-A-02-AP01

July 2021

BONNEVILLE POWER ADMINISTRATION

**2022 POWER RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS**

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APPENDIX

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service

DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources

IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
KSI	key strategic initiative
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff

O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)

SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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POWER RATE SCHEDULES

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POWER RATE SCHEDULES

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SCHEDULE PF-22 PRIORITY FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of Firm Requirements Power by public bodies, cooperatives, and Federal agencies pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). 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.

This schedule is also available for the contract purchase of Residential Exchange Program Power by utilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). Purchases are made 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, 2021, this rate schedule supersedes the PF-20 rate schedule. Sales under the PF-22 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 Contract High Water Mark (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:

Customer Charge Rate in dollars per percentage point of billing determinant			
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Customer Rate	1,998,417	(329,943)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer Billing Determinants are specified in the following table:

Customer Charge Billing determinant for each rate			
	<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:

$$\frac{\text{Minimum of the Customer's:} \\ \text{a) RHW, or} \\ \text{b) Forecast Net Requirement for each} \\ \text{Fiscal Year}}{\text{Sum of all Customers' RHWs}} \times 100$$

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 website. A customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

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.G.

2.1.2 Demand Charge

The Demand Charge is applicable to customers that purchase the following products: Load Following and Block with Shaping Capacity.

2.1.2.1 Demand Rate

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

2.1.2.2 Demand Billing Determinant

The Demand Billing Determinant for each billing month equals:

$$\textit{Tier 1 CSP} - \textit{aHLH} - \textit{CDQ} - \textit{SuperPeak}$$

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours (HLH) of the month, in kilowatts

aHLH = 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.

If a customer does not supply the Super Peak amount listed in its CHWM Contract, Exhibit A, Section 9, for at least two hours of the Super Peak Period, then the customer does not receive a Super Peak Credit for that month.

The Demand Billing Determinant may be adjusted pursuant to the Demand Rate Billing Determinant Adjustments, GRSP II.D.

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 Light Load Hours (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

Month	Rate in mills/kWh	
	<i>HLH</i>	<i>LLH</i>
October	29.92	28.27
November	31.71	29.14
December	38.76	32.05
January	34.29	25.85
February	34.79	28.29
March	27.57	28.44
April	20.71	25.66
May	16.28	16.30
June	17.15	10.62
July	36.83	21.36
August	35.87	26.85
September	28.15	28.95

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:

Customer's Actual Monthly/Diurnal Tier 1 Load,
in kilowatthours
minus
Customer's System Shaped Load for the relevant
diurnal period, in kilowatthours.

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:

$$RT1SC \times TOCA$$

Where:

RT1SC = RHWM Tier 1 System Capability for the relevant diurnal period, in kilowatthours. The *RT1SC* for each diurnal period of the Rate Period is specified in GRSP II.A.

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.G.

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 Risk Adjustments

The Power Cost Recovery Adjustment Clause (Power CRAC) (GRSP II.O), the Power Reserves Distribution Clause (Power RDC) (GRSP II.P), and the Power Financial Reserves Policy Surcharge (Power FRP Surcharge) (GRSP II.Q) are

adjustments to certain Tier 1 rates that apply to the following products under the PF-22 rate schedule: Load Following, Block, and the Block portion of Slice/Block. Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in Appendix A.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to Section 4.3 of the Tiered Rate Methodology (TRM), 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 of 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 customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

Fiscal Year	Rate in mills/kWh
2022	34.39
2023	32.99

2.2.2.2 Short-Term Billing Determinant

The Short-Term 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.

2.2.3.1 Load Growth Rate

Fiscal Year	Rate in mills/kWh
2022	34.39
2023	32.99

2.2.3.2 Load Growth Billing Determinant

The Load Growth 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.M.1.

3.1 Energy Charge

3.1.1 Energy Rate

Month	Rate in mills/kWh	
	<i>HLH</i>	<i>LLH</i>
October	35.70	34.05
November	37.49	34.92
December	44.54	37.83
January	40.07	31.63
February	40.57	34.07
March	33.35	34.22
April	26.49	31.44
May	22.06	22.08
June	22.93	16.40
July	42.61	27.14
August	41.65	32.63
September	33.93	34.73

The PF Melded energy rates in the table above are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in Appendix A.

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

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

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 under the PF-22 Rate Schedule, specified in GRSP II.M.2, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

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.I.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.I.2.

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.I.3.

5.4 Grandfathered Generation Management Service (GMS)

Load Following customers dedicating to their Tier 1 Load the entire output of an Existing Resource that received GMS under Subscription are subject to a GMS Reservation Fee specified in GRSP II.I.6.

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.

Investor-Owned Utilities	Rates in mills/kWh		
	<i>Base PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Avista	50.31	9.11	59.42220
Idaho Power	50.31	5.36	55.67110
NorthWestern	50.31	12.22	62.52860
PacifiCorp	50.31	18.62	68.92920
Portland General	50.31	13.40	63.71450
Puget Sound Energy	50.31	11.50	61.81030
Consumer-Owned Utilities	<i>Base Tier 1 PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Snohomish County PUD No 1	50.49	3.64	54.13

6.2 Energy Billing Determinant

The Billing Determinant for the PF Exchange Power charge is the customer's Residential Load specified in GRSP II.S, Table H.

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:			
		Firm Requirements			REP
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block	
Calculating Rates (including Discounts and Adjustments)					
A	RHWM Tier 1 System Capability (RT1SC)	X	X		
B	Low Density Discount (LDD)	X	X	X	
C	Irrigation Rate Discount	X	X	X	
D	Demand Rate Billing Determinant Adjustments	X			
E	Load Shaping Charge True-Up Adjustment	X			
F	Tier 2 Rate TCMS Adjustment	X			
G	TOCA Adjustment	X	X	X	
Resource Support Services & Related Services					
I	Resource Support Services and Transmission Scheduling Service	X	X	X	
K	Remarketing	X	X	X	
Transfer Service					
L	Transfer Service Charges	X	X	X	
Other Charges					
M	Unanticipated Load Service	X	X	X	
N	Unauthorized Increase (UAI) Charge	X	X	X	X
Risk Adjustments					
O	Power Cost Recovery Adjustment Clause (Power CRAC)	X	X		
P	Power Reserves Distribution Clause (Power RDC)	X	X		
Q	Power Financial Reserves Policy (Power FRP) Surcharge	X	X		

GRSP II.	Adjustments, Charges, and Special Rate Provisions	<i>Applicable to:</i>			
		Firm Requirements			REP
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>	
Slice True-Up					
R	Slice True-Up Adjustment			X	
Residential Exchange Program					
S	Residential Exchange Program Residential Load				X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment				X
Conservation					
U	Conservation Surcharge	X	X	X	
Payment Options					
W	Flexible Priority Firm Power (PF) Rate Option	X	X	X	
X	Priority Firm Power (PF) Shaping Option	X	X	X	
Informational					
Z	Cost Contributions	X	X	X	X

Appendix	Adjustments and Charges	<i>Applicable to:</i>		
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>
A	Supplemental Information	X	X	X

SCHEDULE NR-22 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, including planned NLSLs, as defined in Exhibit D of a customer’s CHWM Contract. This schedule also 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, 2021, this rate schedule supersedes the NR-20 rate schedule. Sales under the NR-22 rate schedule are subject to the 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

Month	Rate in mills/kWh	
	<i>HLH</i>	<i>LLH</i>
October	81.53	79.88
November	83.32	80.75
December	90.37	83.66
January	85.90	77.46
February	86.40	79.90
March	79.18	80.05
April	72.32	77.27
May	67.89	67.91
June	68.76	62.23
July	88.44	72.97
August	87.48	78.46
September	79.76	80.56

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 7.37 mills/kWh.

2.1.1.2 Risk Adjustments

The NR energy rates in Section 2.1.1 are subject to Risk Adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix A.

2.1.2 Energy Billing Determinant

The Energy Billing Determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

2.2.2 Demand Billing Determinant

The Demand 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 under the NR-22 Rate Schedule, specified in GRSP II.M.3, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

4. Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.J.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.J.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 tables.

GRSP II.	Adjustments, Charges, and Special Rate Provisions
B	Low Density Discount (LDD)
D	Demand Rate Billing Determinant Adjustments
J.1	Energy Shaping Service for NLSLs Charge
J.2	NR Resource Flattening Service Charge
M	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Y	Flexible New Resource Firm Power (NR) Rate Option
Z	Cost Contributions

Appendix	Adjustments and Charges
A	Supplemental Information

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SCHEDULE IP-22 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. 16 U.S.C. § 839c(d).

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, 2021, this rate schedule supersedes the IP-20 rate schedule. Sales under the IP-22 rate schedule are subject to the 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-22 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

Month	Rate in mills/kWh	
	<i>HLH</i>	<i>LLH</i>
October	43.15	41.50
November	44.94	42.37
December	51.99	45.28
January	47.52	39.08
February	48.02	41.52
March	40.80	41.67
April	33.94	38.89
May	29.51	29.53
June	30.38	23.85
July	50.06	34.59
August	49.10	40.08
September	41.38	42.18

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 7.37 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.722 mills/kWh Credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Risk Adjustments

The IP energy rates in Section 2.1.1 are subject to Risk Adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix A.

2.1.2 Energy Billing Determinant

The Energy Billing Determinant is the Energy Entitlement that is specified in the customer’s contract.

2.2 Demand Charge

2.2.1 Demand Rate

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

2.2.2 Demand Billing Determinant

The Demand 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.

Month	Industrial Demand Adjuster (kW)
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 (15.75 MW) is reduced in part or in full through a contract action, then the Industrial Demand Adjuster value in the above table will be reduced proportionately and reflected in Appendix A.

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 tables.

GRSP II.	Adjustments, Charges, and Special Rate Provisions
D	Demand Rate Billing Determinant Adjustments
H	DSI Reserves
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Z	Cost Contributions

Appendix	Adjustments and Charges
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SCHEDULE FPS-22

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, Real Power Losses, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest. This rate schedule is not available for sales of non-firm power outside of the region.

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, 2021, this rate schedule supersedes the FPS-20 rate schedule. Sales under the FPS-22 rate schedule are subject to the 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. 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) firm energy with negotiated curtailment rights; (2) resource support and scheduling services for non-Federal resources not eligible for services under Section 7 of this FPS rate schedule; (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); and (4) non-firm energy within the region.

6.1 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.

7. Services for Non-Federal Resources

7.1 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.I.5.

7.2 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.I.4.

7.3 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.I.7.

8. Unanticipated Load Service

The Unanticipated Load Service Charge under the FPS-22 Rate Schedule, specified in GRSP II.M.4, 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. 16 U.S.C. § 839f(i).

9. Real Power Losses

Power Services may sell energy and capacity to BPA Transmission customers for Real Power Loss returns as defined by BPA Transmission Services. If a customer chooses to purchase losses from Power Services, then the customer must contract with Power Services.

9.1 Energy Rates and Billing Determinants

The energy rate for Real Power Losses will differ depending on whether BPA is a participant in the Western Energy Imbalance Market (EIM). The billing determinants do not change.

9.1.1 Energy Rate when BPA is not an EIM Participant

If BPA is not a participant in the EIM, then the energy rate for Real Power Losses shall be the greater of 0 and the applicable average hourly Powerdex Mid-C Index price for firm power for the hour in which the loss occurred. In the event the hourly Powerdex Mid-C price index is no longer a reliable price

index, the index will be replaced for purposes of Real Power Losses energy charges by an applicable new hourly energy index at a hub at which Northwest parties can trade between October 1, 2021, and September 30, 2023. BPA will provide notice of such a change as soon as practicable.

9.1.2 Energy Rate when BPA is an EIM Participant

If BPA is a participant in the EIM, then the energy rate for Real Power Losses will be the greater of 0 and the applicable hourly average Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred.

9.1.3 Energy Billing Determinants

For BPA Transmission customers taking Point-to-Point (PTP) transmission service the Energy Billing Determinant shall be the hourly scheduled energy amounts, in kilowatthours, multiplied by the applicable loss factor(s) specified in BPA’s Open Access Transmission Tariff (OATT), Schedule 11. For BPA Transmission customers taking Network Integration Transmission (NT) service the Energy Billing Determinant shall be the hourly non-federal resource and/or Slice output schedule amounts, in kilowatthours, multiplied by the applicable loss factor(s) specified in BPA’s OATT, Schedule 11.

9.2 Capacity Rate and Billing Determinants

The Capacity Rate for Real Power Losses is 5.52 mills/kWh. The monthly Capacity Billing Determinant shall be the applicable billing determinant, in kilowatthours, used to calculate the Energy Charge for Real Power Losses described above in Section 9.1.3.

10. 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.

GRSP II.	Adjustments, Charges, and Special Rate Provisions
I.4	Forced Outage Reserve Service (FORS)
I.5	Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)
I.7	Resource Remarketing Service (RRS)
M.4	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
Z	Cost Contributions

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

BPA has requested that the Federal Energy Regulatory Commission approve these rate schedules and GRSPs effective October 1, 2021. 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 associated GRSPs supersede BPA's 2020 Power rate schedules, which became effective October 1, 2019, 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), *codified at 16 U.S.C. § 832 et seq.*, the Regional Preference Act (Pub. L. No. 88-552), *codified at 16 U.S.C. § 837 et seq.*, the Transmission System Act (Pub. L. No. 93-454), *codified at 16 U.S.C. § 838 et seq.*, the Northwest Power Act (Pub. L. No. 96-501), *codified at 16 U.S.C. § 839 et seq.*, and the Energy Policy Act of 1992 (Pub. L. No. 102-486), *codified at 16 U.S.C. § 824(i)-(l)*.

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. Bill 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 shall be applied each day to any unpaid balance. The late payment charge shall be 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 4 percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365. 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 a 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 Transfer Service 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 Transfer Service Delivery Charge. BPA will not assess the Transfer Service 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 Transfer Service 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 website.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. RHWL 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-22 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWL Augmentation. The RT1SC values for the FY 2022–2023 rate period are shown in Table A below.

**Table A
FY 2022-2023 RHWL Tier 1 System Capability**

Month	RT1SC in kWh	
	<i>HLH</i>	<i>LLH</i>
October	2,920,790,265	1,633,134,156
November	3,537,945,171	2,227,488,419
December	3,223,872,736	2,419,334,912
January	2,651,579,725	2,009,469,815
February	2,346,690,122	1,693,143,672
March	2,961,839,251	1,860,906,497
April	2,307,313,633	1,436,906,394
May	3,495,709,674	1,691,934,727
June	3,952,932,913	1,590,173,754
July	3,505,339,310	1,757,589,470
August	3,425,259,154	1,660,955,498
September	2,999,684,994	1,700,507,561

B. 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-22 Composite Customer Charge, PF-22 Non-Slice Customer Charge, PF-22 Load Shaping Charge, PF-22 Load Shaping Charge True-Up Adjustment, PF-22 Demand Charge, the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). The LDD also applies to eligible customers under the PF-22 Melded rate schedule and the NR-22 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.B.

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, Demand Charge, and Risk Adjustments).

The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

An LDD dollar benefit will be calculated by BPA for Slice/Block purchases as though it were 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. The applicable discount percentage will also be applied to the customer's monthly billed risk adjustments, if any. The applicable discount percentage will be adjusted for Above-RHWM 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 (K/I) Ratio

The 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 (C/M) Miles Ratio

The 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 44.68 mills/kWh for FY 2022 and FY 2023.
- (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 B below. The eligible discount percentage will be the sum of the two potential discount percentages for which the customer qualifies, based on Table B. The total eligible discount percentage will not exceed 7 percent and may be adjusted pursuant to Sections 4, 5, and 6 below.

Table B
LDD Eligible Discount percentage

Percentage Discount	Applicable Range for kWh/Investment (K/I) Ratio	Applicable Range for Consumers/Mile (C/M) Ratio
0.0%	$35.0 < X$	$12.0 < X$
0.5%	$31.5 < X \leq 35.0$	$10.8 < X \leq 12.0$
1.0%	$28.0 < X \leq 31.5$	$9.6 < X \leq 10.8$
1.5%	$24.5 < X \leq 28.0$	$8.4 < X \leq 9.6$
2.0%	$21.0 < X \leq 24.5$	$7.2 < X \leq 8.4$
2.5%	$17.5 < X \leq 21.0$	$6.0 < X \leq 7.2$
3.0%	$14.0 < X \leq 17.5$	$4.8 < X \leq 6.0$
3.5%	$10.5 < X \leq 14.0$	$3.6 < X \leq 4.8$
4.0%	$7.0 < X \leq 10.5$	$2.4 < X \leq 3.6$
4.5%	$3.5 < X \leq 7.0$	$1.2 < X \leq 2.4$
5.0%	$X \leq 3.5$	$X \leq 1.2$

4. LDD Phase-In Adjustment

If the customer satisfies the eligibility criteria in Sections 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than 0.5 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 0.5 percent if the calculated eligible discount percentage exceeds the existing discount; or
- (b)** the existing eligible discount percentage minus a maximum of 0.5 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 0.5 percent phase-in adjustment described above shall apply to the most recent eligible discount.

Customers receiving the LDD for the first time shall receive the full discount amount as determined in Section 3.

When determining the LDD percentage pursuant to Sections 3 and 4, the calculations shall not include any Additional Adjustment for Very Low Densities as determined in Section 5.

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 the annual determination of the eligible discount percentage pursuant to Sections 3 and 4 above, an additional 0.5 percent shall be added to the customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent.

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.

C. 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 10.90 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 of the Contract 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 RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a 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 kilowatthour 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.

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 10 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 an 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. 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

Fiscal Year	Rate in mills/kWh
2022	-6.11
2023	-6.11

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See Appendix A, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

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.G, 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).

$$\text{Above-Forecast Amount} = \frac{\text{RHWM (calculated)}}{\text{minus TOCA Load (calculated)}}$$

If the 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.

$$\frac{\text{True-Up Charge}}{\text{Billing Determinant}} = \frac{\text{Absolute value of the Annual Deviation}}{\text{minus Above-RHWM Load}}$$

The True-Up Charge Billing Determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

- the customer has Above-RHWM Load, and
- 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.

F. Tier 2 Rate TCMS Adjustment

This adjustment will recover the cost BPA incurs as a result of a transmission event (in the form of either a planned transmission outage or a transmission curtailment) along the transmission path, between the Point of Receipt and the Point of Delivery, used to deliver energy associated with the power purchases for the Tier 2 cost pools. In such a transmission event situation, a TCMS adjustment will be applied to customers' bills if they purchase power at the applicable Tier 2 rate. The method used to calculate the aggregate TCMS adjustment is specified in GRSP II.1.5(c) and (d). The aggregate TCMS adjustment will be allocated to customers based on each customer's proportional energy share of the applicable Tier 2 cost pool.

G. 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-22 7(i) process and will be made available to the customer prior to October 1, 2021. A customer's TOCA for a fiscal year will be revised only as specified below.

The customer's adjusted TOCA will be used to establish 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 to which 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 RHWM 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:

$$\frac{\text{Updated estimate of} \\ \text{Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWMs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-22 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-22 7(i) process.

The Load Following customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Additionally, if the customer's Existing Resource amounts in Exhibit A have changed in accordance with its CHWM Contract, then the customer's TOCA may be updated for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block customer in four circumstances:

- (a) If the customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-22 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 RHWM, and its Forecast Net Requirement used in the BP-22 7(i) process is less than its RHWM, then the customer's TOCA shall be recalculated for that fiscal year using the customer's RHWM.

(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.

(d) If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

H. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to Section 7(c)(3) of the Northwest Power Act, a DSI customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. 16 U.S.C. § 839e(c)(3). 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 offline or the increased generation must be online 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 offline for up to 105 minutes, or increased generation must be available to be online 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 for Operating Reserves – Supplemental is capped at \$5.27 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 offline or the increased generation online 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 offline or increased generation is available to be online.

I. Resource Support Services and Transmission Scheduling Service

Unless stated otherwise, the resource generation amounts used in the calculations below that are from the customer's CHWM Contract are (1) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); (2) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.2(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.2(3) of Exhibit D (Exhibit D hourly average planned amounts).

1. Diurnal Flattening Service (DFS) Charges

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 defined in the customer's CHWM Contract. When DFS charges are coupled with 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.

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 RAM2022 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of hourly generation in excess of average monthly/diurnal Exhibit D planned amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in GRSP II.I.2(a)(1) below. The monthly/diurnal results are summed for the year and divided by the total Exhibit D planned amounts for that same year 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 are 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-22 rate schedule.

(2) DFS Capacity Billing Determinant

The DFS Capacity Billing Determinant is equal to the resource's monthly average Exhibit D HLH planned amounts in one year minus the calculated monthly firm capacity of the resource for that same year.

The RSS module of BPA's RAM2022 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:

- the annual sum of (i) each month's DFS Capacity rates multiplied by (ii) that same month's DFS Billing Determinants; or
- the annual average Exhibit D planned 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.

2. Resource Shaping Charge (RSC) and Resource Shaping Charge Adjustment

(a) 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-22 rate schedule.

(2) Resource Shaping Billing Determinant

The Resource Shaping Billing Determinant for each resource is equal to: (1) the annual average Exhibit A amount converted to a monthly/diurnal shape (in MWh) using the corresponding monthly/diurnal hours for the same year; minus (2) the monthly/diurnal Exhibit D planned amounts or the monthly/diurnal Exhibit A amounts. Generally, RSC does not apply to small, non-dispatchable resources as identified 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 equal to: (i) the sum of the annual average Exhibit A amounts and Resource Remarketing amounts in Exhibit D for the same year; minus (ii) the monthly/diurnal Exhibit D planned amounts.

(3) Calculation of Resource Shaping Charge

For each resource, the RSC 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 in only one fiscal year) to calculate a flat monthly charge.

(b) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the Billing Determinant is equal to Exhibit D planned amounts minus 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 RSC 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 RSC Adjustment is calculated by multiplying the RSC Adjustment rate by the RSC Adjustment Billing Determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

3. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following customer that dedicates the entire output of a hydroelectric Existing Resource with (1) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and (2) 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 GRSP II.I.2(a)(1) above.

(2) SCS Energy Billing Determinant

For each resource, the Energy Billing Determinant is equal to the monthly/diurnal Exhibit A MWh amounts minus the actual monthly/diurnal generation 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-22 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the Billing Determinant is the monthly average 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.

4. 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.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

(2) FORS Capacity Billing Determinant

For each resource, the FORS Capacity 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.I.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 Exhibit D hourly average planned amount, 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.

5. Transmission Scheduling Service (TSS) Charges and Transmission Curtailment Management Service Charge (TCMS)

TSS is a service provided by Power Services to undertake certain scheduling obligations on behalf of the customer. There are two available service levels of TSS: full service (TSS-Full) and partial service (TSS-Partial). TCMS is a feature of TSS (both TSS-Full and TSS-Partial) 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) Transmission Scheduling Service Full Service (TSS-Full) Charge

(1) TSS-Full Rate

Fiscal Year	Rate in mills/kWh
2022	0.11
2023	0.11

(2) TSS-Full Billing Determinant

The TSS-Full Billing Determinants are the annual Exhibit A amounts in kilowatthours. When TSS-Full is provided to a resource to which RRS also applies, the TSS-Full Billing Determinant for each resource is (1) the annual Exhibit A amounts in kilowatthours plus (2) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS-Full Charge

For each eligible resource, the TSS-Full Charge is calculated by multiplying the TSS-Full rate and the TSS-Full 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 and Unspecified Resource Amounts serving Above-RHWM Load are capped such that if the annual cost to the customer using the TSS rate exceeds \$1,003/month, then the monthly charge is capped at \$1,003/month. Charges for Unspecified Resource Amounts serving NLSL and 9(c) export decrement obligations are capped such that if the annual cost to the customer using the TSS rate exceeds \$3,008/month, then the monthly charge is capped at \$3,008/month.

For each TSS-Full customer, BPA will determine the number of resources receiving TSS-Full. 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) Transmission Scheduling Service Partial Service (TSS-Partial) Charge

(1) TSS-Partial Rate

Fiscal Year	\$ per TSS-Partial Event
2022	\$228
2023	\$228

(2) TSS-Partial Billing Determinant

The TSS-Partial Billing Determinant is the total number of TSS-Partial events that occur within a month. Each of the following is considered a single TSS-Partial event:

- (A) a customer, or its scheduling agent, fails to carbon copy (CC) Power Services on a schedule, except if the power being scheduled was purchased from Power Services, including Slice output, and Power Services was included in the market path on the tag; or
- (B) a day that a customer has a TCMS charge.

(3) Calculation of TSS-Partial Charge

The TSS-Partial Charge is calculated by multiplying the TSS-Partial rate by the TSS-Partial Billing Determinant for each month of the rate period.

(c) TCMS Charge if Replacement Power is Provided

If BPA purchases replacement power during a transmission event for a resource supported by TCMS, then the TCMS Charge will be the cost of such purchased

power. If BPA does not purchase replacement power, then the TCMS Charge will be calculated in accordance with the sections below.

(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

The TCMS Charge shall equal the sum of charges for Bands 1 through 3. For each band, the charge shall be calculated as follows:

Apportioned TCMS Billing Determinant multiplied by the TCMS rate multiplied by the Factor in the table below.

Band	Apportioned TCMS Billing Determinant	Factor
	<i>The portion of the TCMS Billing Determinant that is:</i>	
1	Less than or equal to (i) 1.5 percent of the TSS Billing Determinant or (ii) 2 MW, whichever is larger	1.00
2	Greater than the apportioned TCMS Billing Determinant for Band 1, up to and including (i) 7.5 percent of the TSS Billing Determinant or (ii) 10 MW, whichever is larger	1.10
3	Greater than the apportioned billing determinant for Band 2	1.25

(d) 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.

6. Grandfathered Generation Management Service (GMS)

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 2.1.2.1 of the PF-22 rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the GMS Reservation 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.I.1(b)(2).

(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.

7. 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 Remarketing Value in GRSP II.K.3.

(2) RRS Billing Determinant

For each non-Federal resource, the RRS 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.

J. 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 for NLSL Charge

(a) 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 its 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-22 energy rates in Section 2.1.1 of the NR-22 rate schedule to calculate the energy charge (or credit).

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 (1) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 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 (1) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 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).

(b) 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 2022–2023 rate period prior to February 1, 2021. 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-22 rate schedule, Section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify that 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 Charge (NRFS)

The NRFS is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

(a) 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.

(b) NR Resource Flattening Service Energy Rate

The NRFS energy rate is a unique 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.

(c) 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.

K. 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

For each fiscal year, the Tier 2 Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(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, as determined by BPA after the time of the notice, 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 2022–2023.

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 the Remarketing Value in GRSP II.K.3.

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the DFS Remarketing Billing Determinant is (1) the amount of the customer’s non-Federal resource, as specified in the customer’s CHWM Contract Exhibit A, prior to temporary resource removal; less (2) the amount of the customer’s non-Federal resource needed to meet Above-RHWM Load, as specified in the customer’s CHWM Contract Exhibit A, when updated for temporary resource removal.

(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 DFS Remarketing Fee for a customer with a non-Federal resource supported with DFS is zero in FY 2022–2023.

3. Remarketing Value

For each fiscal year, the Remarketing Value rate shall be:

Fiscal Year	Rate in mills/kWh
2022	32.13
2023	30.73

L. Transfer Service Charges

Transfer Service applies to BPA Power Service customers that are served under non-Federal transmission service agreements.

1. Transfer Service Delivery Charge

The Transfer Service 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) Transfer Service Delivery Rate

	<i>Rate in \$/kW</i>
All months	1.27

(b) Transfer Service Delivery Billing Determinant

The monthly billing determinant for the Transfer Service Delivery Charge 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 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 by transfer service; and (2) the customer is not paying BPA Transmission Services for operating reserves for the customer’s load served by transfer.

(a) Transfer Service Operating Reserve Rate

- (1)** The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-22 Operating Reserve – Spinning Reserve Service rate.
- (2)** The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-22 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Service Operating Reserve Billing Determinant

- (1)** The monthly Billing Determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the applicable ACS-22 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the Billing Determinant for Power Services’ charge shall be the amount of the customer’s metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).
- (2)** The monthly Billing Determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the applicable ACS-22 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the Billing Determinant for Power Services’ charge shall be the amount of the customer’s metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service Regulation and Frequency Response Charge

The Transfer Service Regulation and Frequency Response Charge shall apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for Regulation and Frequency Response for the customer’s load served by transfer.

(a) Transfer Service Regulation and Frequency Response Rate

The rate for the Transfer Service Regulation and Frequency Response Charge shall be equal to the ACS-22 Regulation and Frequency Response rate.

(b) Transfer Service Regulation and Frequency Response Billing Determinant

The monthly Billing Determinant for the Transfer Service Regulation and Frequency Response Charge shall be the same as that used for the applicable ACS-22 Regulation and Frequency Response rate, except that the load used to calculate the Billing Determinant for Power Services’ charge shall be the amount of the customer’s total load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

4. Transfer Service Regional Compliance Enforcement Charge

The Transfer Service Regional Compliance Enforcement Rate shall apply to Public customers with load outside the BPA Balancing Authority Area.

(a) Transfer Service Regional Compliance Enforcement Rate

	<i>Rate in mills/kWh</i>
All months	0.03

(b) Transfer Service Regional Compliance Enforcement Billing Determinant

The monthly Billing Determinant for the Transfer Service Regional Compliance Enforcement Charge shall be the public customer’s metered load at points of delivery served by transfer (non-BPA Balancing Authority Area load).

M. Unanticipated Load Service (ULS)

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2021, that results in an unanticipated increase in a customer’s load placed on BPA during the FY 2022-2023 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 on only a temporary basis for the FY 2022-2023 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-22, 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-22, Unanticipated Load is:
 - New Large Single Loads
 - Requirements service requested by investor-owned utilities
- Under FPS-22, 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 ULS or the conclusion of the rate period on September 30, 2023, 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-22 and for resource replacement of a Public Load Following customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 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 ULS in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-22 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

- (A) the applicable diurnal period PF Tier 1 equivalent energy rate (GRSP II.AA); or
- (B) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(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-22 rate schedule.

(2) Demand Billing Determinant

The Demand Billing Determinant shall be the lesser of:

- (A) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month; or
- (B) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-22 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 applicable diurnal period energy rate in Section 2.1.1 of the NR-22 rate schedule; or
- (2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(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 2.2.1 of the NR-22 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-22 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of:

- (A) the applicable diurnal period Resource Replacement rate that equals the PF Tier 1 Equivalent energy rate (GRSP II.AA) from the same diurnal period; or
- (B) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(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

Month	Rate in \$/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

(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.

N. 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 a 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 CSP as compared to the customer's CHWM Contract Exhibit A amounts, not including Super Peak amounts in Section 9 of Exhibit A if any, or Exhibit D amounts, whichever is applicable.

For a Block customer or for the Block portion of the Slice/Block product, the customer's contractual demand entitlement for each HLH shall be the sum of its Tier 1 and Tier 2 HLH predetermined hourly schedule amounts, provided by BPA to the customer 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 at the greater of:

- 150 mills/kWh; or
- 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 is no longer a reliable price index, 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, 2021, and September 30, 2023. BPA will provide notice of such a change as soon as practicable.

0. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that apply to the following products under the PF-22 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power CRAC also applies to power purchased at the PF Melded rate (PF-22), Industrial Firm Power rate (IP-22), and New Resource Firm Power rate (NR-22).

1. Power CRAC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Power CRAC may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power CRAC Amount

The Power CRAC Threshold is an amount of Power RFR below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power CRAC Threshold minus Power RFR.

The Power CRAC Amount is based on the underrun minus the Revenue Financing Amount, limited by the Maximum Power CRAC Recovery Amount (the Power CRAC Cap.) There are four possibilities:

- (1) If the underrun minus the Revenue Financing Amount is less than \$5 million, there is no Power CRAC.

- (2) If the underrun minus the Revenue Financing Amount is greater than or equal to \$5 million and less than or equal to \$100 million, the Power CRAC Amount is equal to the underrun minus the Revenue Financing Amount.
- (3) If the underrun minus the Revenue Financing Amount is greater than \$100 million and less than \$500 million, the Power CRAC Amount is equal to \$100 million plus one-half of the difference between \$100 million and the underrun minus the Revenue Financing Amount.
- (4) If the underrun minus the Revenue Financing Amount is greater than or equal to \$500 million, the Power CRAC Amount is equal to \$300 million.

The Power CRAC Cap and Thresholds are shown in Table C.

Table C
Power CRAC Annual Thresholds and Caps
(dollars in millions)

Power RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2021	2022	\$0	\$30	\$300
2022	2023	\$0	\$31	\$300

2. Power CRAC Surcharge Rate

(a) Calculating the Power CRAC Surcharge Rate

The Power CRAC Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Power CRAC Amount}}{\sum BD}$$

$$\sum BD$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- Service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power CRAC Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power CRAC Surcharge rate will be applied to the sum of each customer’s HLH and LLH PF System Shaped Load for December through September of the applicable year. A customer’s Low Density Discount shall be applied to the Power CRAC.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power CRAC Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power CRAC Surcharge Rate

An Annual Power CRAC Surcharge rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power CRAC Surcharge rate is calculated by dividing the Power CRAC Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power CRAC Surcharge rate will be:

- (1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)
- (2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power CRAC Amount.

(b) Notification of Power CRAC

By November 30, 2021, BPA will complete the calculation of Power RFR as of the end of FY 2021, for use in calculating the Power CRAC applicable to rates for

December through September of FY 2022. By November 30, 2022, BPA will complete the calculation of Power RFR as of the end of FY 2022, for use in calculating the Power CRAC applicable to rates for December through September of FY 2023.

If the Power CRAC triggers, BPA will notify customers of the preliminary Power CRAC Amount to be recovered by the Power CRAC Surcharge rate for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge.

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power CRAC Amount, the Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power CRAC Amount, Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Power RDC is calculated each fiscal year.

If the Power RDC quantitative criteria (below) are met, the Administrator will calculate the Power RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Power Dividend Distribution (Power DD), distribution to customers, or any other Power-specific purposes determined by the Administrator.

A Power DD is a downward adjustment to certain rates that apply to the following products under the PF-22 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power DD also applies to power purchased at the PF Melded rate (PF-22), Industrial Firm Power rate (IP-22), and New Resource Firm Power rate (NR-22).

1. Power RDC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) and financial reserves available for risk that are attributed to BPA (BPA RFR) as of the fiscal year preceding the applicable year. If Power RFR is greater than the Power RDC Threshold for that applicable year by at least \$5 million, and BPA RFR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine a Power RDC Amount. If the Administrator determines that all or part of the Power RDC Amount

will be applied to a Power DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power RDC Amount

The Power RDC can trigger only if (1) Power RFR exceeds the Power RDC Threshold, and (2) BPA RFR exceeds the BPA RDC Threshold.

The Power RDC Amount is the amount of Power RFR that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a Power DD, distribute to customers, or any other Power-specific purposes determined by the Administrator. The Power RDC Amount will be the smallest of Power RFR minus the Power RDC Threshold, BPA RFR minus the BPA RDC Threshold, or the Power RDC Cap.

Table D.1
Power RDC Annual Thresholds and Caps
(dollars in millions)

Power RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Power RFR Threshold	Maximum RDC Amount (Cap)
2021	2022	\$603	\$500
2022	2023	\$603	\$500

Table D.2
BPA RDC Annual Thresholds
(dollars in millions)

BPA RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	BPA RFR Threshold
2021	2022	\$605
2022	2023	\$605

2. Power DD Credit Rate

If the Administrator elects to apply all or a portion of a Power RDC Amount to reduce Power rates, then the following Power DD Credit rate shall apply:

(a) Calculating the Power DD Credit Rate

The Power DD Credit rate in mills per kilowatthour shall be:

Power RDC Amount being used for a Power DD

$$\sum BD$$

Where:

$\sum BD$ (Sum of Billing Determinants) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(a) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power DD Credit rate will be subtracted from the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power DD Credit rate will be applied to the sum of each customer’s HLH and LLH PF System Shaped Load, multiplied by -1, for December through September of the applicable year. A customer’s Low Density Discount shall be applied to the Power DD, which will be a charge.

(b) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power DD Credit rate will be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(c) Annual Power DD Credit Rate

An Annual Power DD Credit rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power DD Credit rate is calculated by dividing the Power RDC Amount being used for a Power DD by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power DD Credit rate will be:

- (1) Added to the Load Shaping Charge True-Up rate (GRSP II.E, Section 1); and
- (2) Added to the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power RDC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function. For the Second and Third Quarter Reviews, BPA will post to its external website (www.bpa.gov) a preliminary forecast of the Power RDC Amount.

(b) Notification of Power RDC

By November 30, 2021, BPA shall complete the calculation of Power RFR and BPA RFR as of the end of FY 2021, for use in calculating the Power RDC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Power RFR and BPA RFR as of the end of FY 2022, for use in calculating the Power RDC applicable to rates for December through September of FY 2023.

If the Power RDC triggers, BPA will notify customers of the preliminary Power RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Power purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power RDC Amount.

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power RDC Amount, and if applicable, the Power DD Credit rate and Annual Power DD Credit rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power RDC Amount as soon as practicable, but in no case later than December 15 of each applicable year.

Q. Power Financial Reserves Policy Surcharge (Power FRP Surcharge)

The Power FRP Surcharge is an upward adjustment to certain rates that apply to the following products under the PF-22 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power FRP Surcharge also applies to power purchased at the PF Melded rate (PF-22), Industrial Firm Power rate (IP-22), and New Resource Firm Power rate (NR-22).

1. Power FRP Surcharge Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) as of the end of the fiscal year preceding the applicable

year. Based on the calculations below, a Power FRP Surcharge may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power FRP Surcharge Amount

The Power FRP Surcharge Threshold is an amount of Power RFR, below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power FRP Surcharge Threshold minus Power RFR.

The Power FRP Surcharge Amount is based on the underrun minus the Revenue Financing Amount, limited by the Base Surcharge. There are three possibilities:

- (1)** If the underrun minus the Revenue Financing Amount is less than \$5 million, there is no Power FRP Surcharge.
- (2)** If the underrun minus the Revenue Financing Amount is greater than or equal to \$5 million and less than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the underrun minus the Revenue Financing Amount.
- (3)** If the underrun minus the Revenue Financing Amount is greater than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the Base Surcharge.

The Power FRP Surcharge Thresholds and Base Surcharges are shown in Table E.

**Table E
Power FRP Surcharge Annual Thresholds and Caps
(dollars in millions)**

Power RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Base Surcharge
2021	2022	\$302	\$30	\$40
2022	2023	\$302	\$31	\$40

2. Power FRP Surcharge Rate

(a) Calculating the Power FRP Surcharge Rate

The Power FRP Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Power FRP Surcharge Amount}}{\sum BD}$$

Where:

Σ *BD* (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power FRP Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power FRP Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for December through September of the applicable year. A customer's Low Density Discount will be applied to the Power FRP Surcharge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power FRP Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power FRP Surcharge Rate

An Annual Power FRP Surcharge rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power FRP Surcharge rate is calculated by dividing the Power FRP Surcharge Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power FRP Surcharge rate will be:

- (1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)
- (2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power FRP Surcharge Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function.

For the second and third quarter reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power FRP Surcharge Amount.

(b) Notification of Power FRP Surcharge

By November 30, 2021, BPA shall complete the calculation of Power RFR as of the end of FY 2021, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Power RFR as of the end of FY 2022, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2023.

If the Power FRP Surcharge triggers, BPA will notify customers of the preliminary Power FRP Surcharge Amount to be recovered by the Power FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge..

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power FRP Surcharge Amount, the Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power FRP Surcharge Amount, Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

R. Slice True-Up Adjustment

Pursuant to Section 2.7 of the TRM, BP-12-A-03, Slice customers will 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 will be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November).

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:
the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period,

from

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 F) 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-22 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.

- (3) the sum of forecast TOCAs is the sum of TOCAs used to set the PF-22 Composite Customer rate; and
- (4) the Change in Unused RHWL Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWL Revenue = (Actual Unused RHWL – Forecast Unused RHWL) × 35.55 mills/kWh.

Actual Unused RHWL = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWL Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

Forecast Unused RHWL = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWL 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-22 7(i) process;
- (2) 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 – 13.95 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.

–13.95 mills/kWh is calculated by the equation:

$$PFMEES - 8.17 \text{ mills/kWh}$$

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of -5.78 mills/kWh and is subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q).

See Appendix A, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice 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 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 Exhibits 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 F
Composite Cost Pool True-Up Table

	Actual Data (\$000)	FY 2022 forecast (\$000)	FY 2023 forecast (\$000)
1 Operating Expenses			
2 Power System Generation Resources			
3 Operating Generation			
4 COLUMBIA GENERATING STATION (WNP-2)		278,643	304,748
5 BUREAU OF RECLAMATION		152,269	152,963
6 CORPS OF ENGINEERS		252,557	252,557
7 CRFM STUDIES		7,266	3,619
8 LONG-TERM CONTRACT GENERATING PROJECTS		16,036	17,123
9 Sub-Total		706,771	731,010
10 Operating Generation Settlement Payment and Other Payments			
11 COLVILLE GENERATION SETTLEMENT		22,000	22,000
12 OPERATING GENERATION SETTLEMENT PAYMENT (SPOKANE)		5,749	5,500
13 Sub-Total		27,749	27,500
14 Non-Operating Generation			
15 TROJAN DECOMMISSIONING		1,200	1,200
16 WNP-1&3 DECOMMISSIONING		1,141	1,175
17 Sub-Total		2,341	2,375
18 Gross Contracted Power Purchases			
19 PNCA HEADWATER BENEFITS		3,100	3,100
20 OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		-	-
21 Sub-Total		3,100	3,100
22 Bookout Adjustment to Power Purchases (omit)			
23 Augmentation Power Purchases (omit - calculated below)			
24 AUGMENTATION POWER PURCHASES		-	-
25 Sub-Total		-	-
26 Exchanges and Settlements			
27 RESIDENTIAL EXCHANGE PROGRAM (REP)		265,773	265,762
28 OTHER SETTLEMENTS		-	-
29 Sub-Total		265,773	265,762
30 Renewable Generation			
31 RENEWABLES (excludes KIII)		26,255	20,132
32 Sub-Total		26,255	20,132
33 Generation Conservation			
34 CONSERVATION ACQUISITION (Purchases)		67,357	67,357
35 CONSERVATION INFRASTRUCTURE		27,300	27,300
36 LOW INCOME WEATHERIZATION & TRIBAL		6,005	6,005
37 REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT		8,000	8,000
38 DR & SMART GRID		215	215
39 LEGACY		590	590
40 MARKET TRANSFORMATION		11,800	11,800
41 Sub-Total		121,267	121,267
42 Power System Generation Sub-Total		1,153,255	1,171,146
43 Power Non-Generation Operations			
44 Power Services System Operations			
45 EFFICIENCIES PROGRAM		-	-
46 INFORMATION TECHNOLOGY		3,804	3,780
47 GENERATION PROJECT COORDINATION		3,947	4,035
48 SLICE IMPLEMENTATION		971	1,003
49 Sub-Total		8,721	8,818
50 Power Services Scheduling			
51 OPERATIONS SCHEDULING		9,600	9,910
52 OPERATIONS PLANNING		8,708	9,006
53 Sub-Total		18,308	18,917
54 Power Services Marketing and Business Support			
55 GRID MOD		2,223	2,285
56 EIM INTERNAL SUPPORT		-	-
57 POWER INTERNAL SUPPORT		13,976	14,825
58 POWER R&D		2,527	2,527
59 SALES & SUPPORT		15,172	15,563
60 STRATEGY, FINANCE & RISK MGMT		3,566	3,679
61 EXECUTIVE AND ADMINISTRATIVE SERVICES		6,672	6,886
62 CONSERVATION SUPPORT		7,876	8,131
63 Sub-Total		52,013	53,895
64 Power Non-Generation Operations Sub-Total		79,042	81,630

**Table F, continued
Composite Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2022 forecast (\$000)	FY 2023 forecast (\$000)
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**Table F, continued
Composite Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2022 forecast (\$000)	FY 2023 forecast (\$000)
119 DSI Revenue Credit			
120 Revenues 12 aMW @ IP rate		4,277	4,277
121 Total DSI revenues		4,277	4,277
122			
123 Minimum Required Net Revenue Calculation			
124 Principal Payment of Fed Debt for Power		495,001	525,000
125 Repayment of Non-Federal Obligations (EN Line of Credit)		-	-
126 Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)		16,005	21,111
127 Irrigation assistance		16,060	12,762
128 Sub-Total		527,066	558,873
129 Depreciation		140,949	144,155
130 Amortization		357,654	355,682
131 Capitalization Adjustment		(45,937)	(45,937)
132 Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)		(7,562)	(7,491)
133 Amortization of Cost of Issuance (MRNR-reverse sign)		169	169
134 Cash freed up by DSR refinancing		-	-
135 Gains/Losses on Extinguishment		16,510	16,865
136 Prepay Revenue Credits		(30,600)	(30,600)
137 Non-Federal Interest (Prepay)		7,854	6,799
138 Contribution to decommissioning trust fund		(4,472)	(4,651)
139 Gains/losses on decommissioning trust fund		(9,857)	(10,198)
140 Interest earned on decommissioning trust fund		(3,399)	(3,516)
141 Revenue Financing Requirement		(40,000)	(40,000)
142 Sub-Total		381,309	381,276
142 Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses		145,758	177,597
143 Minimum Required Net Revenues		145,758	177,597
144			
145 Annual Composite Cost Pool (Amounts for each FY)		2,331,204	2,370,827
146			
147 SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL			
148 TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)			
149 Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)			
150 TRUE-UP ADJUSTMENT CHARGE BILLED (22.3627 percent)			
151			

**Table G
Slice Cost Pool True-Up Table**

	Audited Actual Data (\$000)	FY 2022 forecast (\$000)	FY 2023 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)			

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are shown in Table H below. These loads are applicable to each year of the rate period, FY 2022 and FY 2023, and are established pursuant to Section 2 of the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement).

Table H
Residential Load for the BP-22 Rate Period (in kWh)

Month	Avista	Idaho	NorthWestern
October	260,372,685	474,144,755	48,500,471
November	326,963,145	477,208,540	58,449,310
December	426,398,563	585,230,751	69,349,360
January	430,207,922	619,849,460	75,257,578
February	396,228,677	581,817,321	68,547,618
March	422,301,695	542,520,681	70,040,314
April	321,131,118	458,191,769	59,323,287
May	260,985,024	488,575,450	50,780,069
June	251,590,928	530,993,173	49,460,061
July	272,462,999	654,647,900	51,987,708
August	311,984,191	767,198,393	58,492,686
September	290,830,996	676,693,588	53,934,490

Month	PacifiCorp	Portland General	Puget Sound
October	593,931,939	850,292,429	814,425,572
November	734,342,136	1,010,799,869	986,270,988
December	985,950,807	1,308,439,612	1,297,421,620
January	964,346,765	1,279,182,117	1,293,469,811
February	891,813,060	1,175,004,839	1,286,740,139
March	848,938,916	1,168,115,480	1,283,103,341
April	690,493,917	992,429,305	1,028,327,098
May	580,060,281	843,835,124	850,106,349
June	631,519,549	868,651,400	790,291,474
July	715,186,652	905,097,953	758,382,721
August	797,533,028	1,004,724,793	777,650,497
September	713,043,047	985,191,737	786,253,922

T. Residential Exchange Program 7(b)(3) Surcharge 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-22 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-22 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, changes in service territory). 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-22 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 will be accomplished by substituting all modified ASCs and recomputing the rates in Section 6.1 of the PF-22 rate schedule. This recomputation will be accomplished by:

1. Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to \$/MWh).
2. Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-22 7(i) proceeding.
3. 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.
4. Summing the unconstrained benefits for each participant to compute total unconstrained benefits.
5. Computing the difference between the total unconstrained benefits and \$530,644,118 (the total REP benefits adopted for the two-year rate period in the BP-22 7(i) proceeding).
6. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.
7. 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 Tables 2.4.11 and 2.4.12 of the Power Rates Study Documentation, BP-22-E-BPA-01A. Table 2.4.11 will be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges will take effect on the day that the utility's modified ASC takes effect. This adjustment will 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 website.

U. 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-22 (including Slice purchasers), NR-22, and IP-22 rate schedules.

V. [Reserved for Future Use]

W. 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-22 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-22 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-22 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-22 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.

X. 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-22 rate schedule may agree to a PF-22 Tier 1 Customer Charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-22 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to "shape" certain PF-22 Tier 1 Customer Charges within the fiscal

year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-22 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, 2021.

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:

- **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.
- **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. 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.

Y. Flexible New Resource (NR) Firm Power 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-22 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, 3, 4 and 5 of the NR-22 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, 3, 4 and 5 of the NR-22 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-22 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.

Z. Cost Contributions

Pursuant to Section 7(j) of the Northwest Power Act (16 U.S.C. § 839e(j)), BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is shown in Table I.

**Table I
Resource Cost Contribution**

Rate Schedule	Federal Base System	Exchange Resources	New Resources
PF	39.79%	60.21%	0.00%
IP	0.00%	68.34%	31.66%
NR	0.00%	68.35%	31.65%
FPS	0.00%	70.29%	29.71%

2. The cost of resources acquired to meet load growth within the region is estimated to be 33.65 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 46.88 mills/kWh.

AA. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates, shown in Table J below, 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.

**Table J
PF Tier 1 Equivalent Rates**

Month	Energy Rate in mills/kWh		Demand Rate in \$/kW
	<i>HLH</i>	<i>LLH</i>	<i>HLH</i>
October	36.03	34.38	9.87
November	37.82	35.25	10.46
December	44.87	38.16	12.78
January	40.40	31.96	11.31
February	40.90	34.40	11.47
March	33.68	34.55	9.09
April	26.82	31.77	6.83
May	22.39	22.41	5.36
June	23.26	16.73	5.65
July	42.94	27.47	12.14
August	41.98	32.96	11.83
September	34.26	35.06	9.29

These rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See Appendix A, Supplemental Information, for adjusted PF Tier 1 Equivalent rates.

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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-22), New Resources Firm Power (NR-22), and Firm Power and Surplus Products and Services (FPS-22) 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 online 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. 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.

8. 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.

9. 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.

10. 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.

11. 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.

12. 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 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.

13. 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). 16 U.S.C. § 839c(c). 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.

14. 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.

15. 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.

16. 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.

17. 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.

18. Transfer Service

As defined in the CHWM Contracts, Transfer Service means the transmission, distribution and other services provided by a third party transmission provider to deliver electric energy and capacity over its transmission system.

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 TRM, 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 RHW in the RHW 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.H, 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. 16 U.S.C. § 839c(b).

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. Remarketing Value

The Remarketing Value is the value BPA returns to customers for remarketed Tier 2 and non-Federal energy. This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. If BPA makes a transaction for a flat annual block of power (between November 1, 2020 and June 1, 2021) to be delivered in a fiscal year in the upcoming Rate Period, then the Remarketing Value for that fiscal year is based on the price of that transaction. If multiple transactions are made, then the Remarketing Value for that fiscal year is based on the weighted-average price of all transactions for the applicable delivery fiscal year. Otherwise, the Remarketing Value for a fiscal year is based on average ICE MID-C settlement prices from two separate five consecutive-business-day periods (the last full week in September 2020 and the last full week March 2021) for a flat block of annual power in the same fiscal year, plus \$0.50 per megawatthour.

25. 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).

26. 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.

27. 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.

28. RHWMTier 1 System Capability (RT1SC)

As defined in the TRM, RHWMTier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWMTier 1 Augmentation. The RT1SC table of values may be found at GRSP II.A, Table A.

29. 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.

30. 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 2022–2023 are as follows (HE = Hour Ending):

October – May	HE 7 through HE 9 and HE 18 through HE 20
June – September	HE 15 through HE 20

31. 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 RHWMTier 1 System Capability through such periods.

32. 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 website.

33. 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.

34. 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.

35. 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.

36. 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.

37. 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.

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APPENDIX

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Power Rates Schedules and GSRPs

Appendix A: Supplemental Information

Any adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q) will be summarized here. Any other adjustments to rates or GRSPs during the Rate Period, made in accordance with these rate schedules and GRSPs, will also be summarized here.

BP-22 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix C:
2022 Transmission, Ancillary, and
Control Area Service Rate Schedules
and General Rate Schedule Provisions
(FY 2022–2023)

BP-22-A-02-AP02

July 2021



BONNEVILLE POWER ADMINISTRATION

**2022 TRANSMISSION, ANCILLARY, AND
CONTROL AREA SERVICE RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS**

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also NPCC)
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service

DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	Generation Imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review

IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
KSI	key strategic initiative
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MO	market operator
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation

NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCS	Secondary Crediting Service

SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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**TRANSMISSION, ANCILLARY, AND CONTROL AREA
SERVICE RATE SCHEDULES**

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FPT-22.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-20.1 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 (FCRTS). 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 for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$0.778 \text{ kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-22 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	\$0.0774 per mile
2. Main Grid Interconnection Terminal	\$0.81/kW
3. Main Grid Terminal	\$0.89/kW
4. Main Grid Miscellaneous Facilities	\$4.42/kW
SECONDARY SYSTEM CHARGES	
1. Secondary System Distance	\$0.7600 per mile
2. Secondary System Transformation	\$8.32/kW
3. Secondary System Intermediate Terminal	\$3.22/kW
4. Secondary System Interconnection Terminal	\$2.27/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.

C. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

D. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

E. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

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FPT-22.3
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-20.3 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 (FCRTS). 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 2022 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 for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$0.733 \text{ kW/mo}} \right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-22 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	\$0.0728 per mile
2. Main Grid Interconnection Terminal	\$0.76/kW
3. Main Grid Terminal	\$0.84/kW
4. Main Grid Miscellaneous Facilities	\$4.15/kW
SECONDARY SYSTEM CHARGES	
1. Secondary System Distance	\$0.7160 per mile
2. Secondary System Transformation	\$7.83/kW
3. Secondary System Intermediate Terminal	\$3.03/kW
4. Secondary System Interconnection Terminal	\$2.14/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 2023 Rates

The monthly charge per kilowatt 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 for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$0.778 \text{ kW/mo}} \right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-22 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	\$0.0773 per mile
2. Main Grid Interconnection Terminal	\$0.81/kW
3. Main Grid Terminal	\$0.89/kW
4. Main Grid Miscellaneous Facilities	\$4.41/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.7601 per mile
2. Secondary System Transformation	\$8.31/kW
3. Secondary System Intermediate Terminal	\$3.22/kW
4. Secondary System Interconnection Terminal	\$2.27/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.

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NT-22 NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-20 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 (OATT). 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

\$2.031 per kilowatt per month

SECTION III. BILLING FACTOR

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.

Except as provided below, 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 = \$2.031 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.

Notwithstanding the formula above, the amount of the credit given for a particular DNR SD will be limited to the amount of the monthly charges for NT Service for that DNR SD.

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.

H. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

I. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

J. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

K. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.J.

PTP-22 POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-20 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. Terms and conditions of PTP service are specified in the Open Access Transmission Tariff (OATT). 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

\$1.648 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 \$0.076 per kilowatt per day

b. Day 6 and beyond \$0.054 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.740 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)

Reservations for Long-Term Firm PTP Transmission Service that use BPA transmission facilities for a distance of less than 75 circuit miles shall receive a SDD. The SDD shall be designated in the PTP Service Agreement.

For reservations receiving a SDD, BPA will multiply the billing factors in Section III.A. by the following factor to calculate the customer's monthly transmission bill:

$$0.6 + (0.4 * \text{transmission distance} / 75).$$

System sales do not qualify for SDD. 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 redirects in the short term, on a firm or non-firm basis, any portion of Reserved Capacity from a reservation receiving a SDD for any period of time during a month, the SDD shall not be applied to the entire reservation for 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.

K. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

L. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

M. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

N. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.J.

IS-22
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-20 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 (OATT) 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

\$1.118 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** \$0.051 per kilowatt per day
- b. Day 6 and beyond** \$0.037 per kilowatt per day

2. Hourly Firm and Non-Firm Service

10.290 mills per kilowatthour

BPA intends to provide discounted service for Hourly Non-Firm Service in the south-to-north direction. BPA will post such discount on OASIS pursuant to Section II.E of the GRSPs. The following principles will apply to any such discount:

- a. Providing a discount for service in one direction will not require the same discount to be provided in the other direction.
- b. Providing a discount for service on the Southern Intertie will not require a discount to be provided for service on the Network or other segments.

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.

I. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

J. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

L. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.J.

IM-22
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-20 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 (OATT). 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

\$0.524 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 \$0.024 per kilowatt per day

b. Day 6 and beyond \$0.017 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.510 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 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 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.

I. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

J. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) surcharge, specified in GRSP II.I.

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UFT-22
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-20 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-22 ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-20 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-22 TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-20 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 (FCRTS). 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

$$\text{Intertie Charge} = [((TAC / 12) - NFR) * \frac{(CR - EC)}{TCR}]$$

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.

RC-22
REGIONAL COMPLIANCE ENFORCEMENT AND REGIONAL COORDINATOR
RATES

SECTION I. AVAILABILITY

This schedule supersedes the RC-20 rate schedule. The rates in this schedule recover the costs billed to BPA by the “regional entity” and the “reliability coordinator” for reliability compliance monitoring and enforcement and reliability coordination services. The rates apply to all loads in the BPA Control Area except for loads of customers billed directly by the regional entity and the reliability coordinator. 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. Regional Compliance Enforcement Rate

0.04 mills per kilowatthour

B. Regional Coordinator Rate

0.04 mills per kilowatthour

SECTION III. BILLING FACTORS

The Billing Factor is the customer’s total load in the BPA Control Area, in kilowatthours.

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OS-22 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-20 rate schedule. The Oversupply Rate applies to generators in the BPA balancing authority area (BAA) 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 Resource 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, 2022, through September 30, 2023. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2022-2023 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 BAA, 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 Resource 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.M.

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-22
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-20 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 1.380 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.

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ACS-22 ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-20 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff (OATT) 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

C. Energy Imbalance Market Services And Rates

EIM Service is used to meet the Energy Imbalance (EI) and Generation Imbalance (GI) obligations of loads and resources in the BPA Control Area or balancing authority area (BAA), and optimize the transmission system by economically dispatching generating resources across the EIM footprint. All Transmission Customers are subject to EIM charges and credits. The BPA BAA receives charges and credits from the California Independent System Operator (CAISO or Market Operator (MO)) for the BPA BAA on behalf of all loads, Interchange, and non-participating resources in the BAA in accordance with Section 29 of the Market Operator Tariff. This section allocates the charges and credits received by the BPA BAA.

1. EIM Imbalance Charges
 - a. Energy Imbalance (EI) Service (Tariff Schedule 4E)
 - b. Generator Imbalance (GI) Service (Tariff Schedule 9E)
2. Interchange and Intrachange Imbalance
3. Charges for Under-Scheduling or Over-Scheduling Load
4. EIM Neutrality and Uplift Charges and Credits
5. Rolled In Charges
6. Other Charges and Provisions

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 and on the Southern Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. Rates

a. NT Service

The rate shall not exceed \$0.389 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed \$0.316 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 \$0.015 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 0.910 mills per kilowatthour.

2. Billing Factors

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP and IS), 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 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.

These Billing Factors apply to all PTP transmission service under the OATT 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 of the Network Integration Rate Schedule (NT-22).

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 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 calculated for each quarter, beginning October 2021, according to the formulas below. The rates will be posted on BPA's website and updated as needed. 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 = 505,272 MW= Average of forecasted FY 2022 and FY 2023 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, 2021, 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, 2021 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 three-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 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.

These Billing Factors apply to all PTP transmission service under the OATT 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 of the Network Integration Rate Schedule (NT-22).

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 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. RFR Service is the continuous balancing of resources with load by providing 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. Non-EIM and EIM Rates

a. Non-EIM Rate

The rate shall not exceed 0.46 mills per kilowatthour.

b. EIM Rate

The rate shall not exceed 0.43 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 (Tariff Schedule 4)

The rates below apply to Transmission Customers taking EI Service from BPA when such services are provided pursuant to Schedule 4 of the BPA Tariff.

EI Service under Schedule 4 is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA BAA 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 EI (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

Transmission Customers taking EI Service shall be subject to the Persistent Deviation Penalty Charge pursuant to GRSP II.L.2.

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 11.05 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 12.71 mills per kilowatthour.

For energy delivered, the generator shall purchase the energy at the hourly market index price, or the LMP at the closest point of interconnection if BPA is in the EIM, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 7.22 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 8.30 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall purchase the energy at the hourly market index price, or the LMP at the closest point of interconnection if BPA is in the EIM, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 RFR Service from the BPA Control Area, and such RFR Service is not provided for under a BPA transmission agreement. RFR Service is the continuous balancing of resources with load by providing 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. Non-EIM and EIM RFR Rates

a. Non-EIM Rate

The rate shall not exceed 0.46 mills per kilowatthour.

b. EIM Rate

The rate shall not exceed 0.43 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 (Schedule 9)

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance (GI) Service is provided for in an interconnection agreement or other arrangement. The rates below shall apply when such services are provided pursuant to Schedule 9 of the BPA Tariff.

GI Service under Schedule 9 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 GI (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. 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.

d. 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 11.05 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 12.71 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, or the LMP at the closest point of interconnection if BPA is in the EIM, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 7.22 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 8.30 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, or the LMP at the closest point of interconnection if BPA is in the EIM, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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) is comprised of two components: regulating reserves (which compensate for moment-to-moment differences between generation and load) and non-regulating reserves (which compensate for larger differences occurring over longer periods of time during the hour). VERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

2. Balancing Service

The total charge for VERBS is the applicable rate in Section 2.a. or 2.b., below, plus Direct Assignment Charges under Section 3 and Intentional Deviation Penalty Charges under Section 4.

a. Non-EIM and EIM VERBS Rates For Wind Resources

(1) Non-EIM VERBS Rates

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (A) Regulating Reserves \$0.477 per kilowatt per month
- (B) Non-Regulating Reserves \$0.570 per kilowatt per month

(2) EIM VERBS Rates

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (A) Regulating Reserves \$0.467 per kilowatt per month
- (B) Non-Regulating Reserves \$0.514 per kilowatt per month

b. Non-EIM and EIM VERBS Rates For Solar Resources

(1) Non-EIM VERBS Rates

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (A) Regulating Reserves \$0.174 per kilowatt per month
- (B) Non-Regulating Reserves \$0.115 per kilowatt per month

(2) EIM VERBS Rates

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (A) Regulating Reserves \$0.170 per kilowatt per month
- (B) Non-Regulating Reserves \$0.105 per kilowatt per month

c. Billing Factor

The Billing Factor for rates in Section 2.a and 2.b is as follows:

- (1) For each plant, or phase of a 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 plant, or phase of a 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 plant, or phase of a 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.

d. Exceptions

- (1) The rates under Section 2.a and 2.b 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 BAA to another BAA.
- (2) Individual rate components under Sections 2.a and 2.b 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 VERBS, including by contractual arrangements for third-party supply.

3. Direct Assignment Charges

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide VERBS to the customer if:

- a. the customer elected to self-supply in accordance with Section 2.d. but is unable to self-supply one or more components to VERBS; or
- b. the customer has a projected generator interconnection date after FY 2023, but chooses to interconnect during the FY 2022-2023 rate period; or
- c. the customer elected to dynamically transfer its resource out of BPA's BAA, but the resource remains in the BPA BAA after the date specified in the customer election.

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 \$0.168 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.

4. Intentional Deviation Penalty Charge

Customers taking VERBS under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.K.

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 DERBS is the charge determined by applying the rates in Section 1 below, plus Direct Assignment Charges in Section 4 below.

1. Non-EIM and EIM DERBS Rates

a. Non-EIM Rates

The rates for DERBS shall not exceed:

- (1) Incremental Reserves 21.629 mills per kW maximum hourly deviation
- (2) Decremental Reserves 1.230 mills per kW maximum hourly deviation

b. EIM Rates

The rates for DERBS shall not exceed:

- (1) Incremental Reserves 21.303 mills per kW maximum hourly deviation
- (2) Decremental Reserves 1.240 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. When BPA is in the EIM, negative Station Control Error for DERBS billing factors will be based on the measurement value used for determining Uninstructed Imbalance Energy (UIE).
- 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. When BPA is in the EIM, positive Station Control Error for

DERBS billing factors will be based on the measurement value used for determining UIE.

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 BAA to another BAA.
- 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 BAA 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 DERBS to the customer if:

- a. the customer elected to self-supply but is unable to self-supply DERBS; or
- b. a customer has a projected generator interconnection date after FY 2023 but chooses to interconnect during the FY 2022-2023 rate period;
- c. a customer operating in another BAA chooses to dynamically transfer into the BPA BAA during the FY 2022-2023 rate period; or

- d. the customer elected to dynamically transfer its resource out of BPA's BAA but the resource remains in the BPA BAA after the date specified in the customer election.

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 \$0.168 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.

5. Persistent Deviation

Transmission Customers taking DERBS shall be subject to the Persistent Deviation Penalty Charge pursuant to GRSP I.L.1.

G. New Generation Technology Pilot Program

A customer and BPA may jointly develop a pilot program at the individual generation project level in order to integrate new uses of technology, such as a solar project coupled with a co-located battery. The goal of the pilot is to reduce the project’s balancing reserve capacity burden placed on the BPA BAA. In place of any normally applicable RFR, VERBS or DERBS rates, BPA will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following capacity rate components:

- (a) Regulating Reserves \$0.261 per kilowatt-day
- (b) Non-Regulating Reserves \$0.168 per kilowatt-day
- (c) DEC Balancing Reserves \$0.012 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project), and shall not exceed the total cost of the normally applicable RFR, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, resulting in the pilot adding to rather than reducing the Station Control Error of the project.

SECTION IV. ENERGY IMBALANCE MARKET SERVICES AND RATES

The rates below shall apply when Energy Imbalance (EI) and Generation Imbalance (GI) services are provided pursuant to Tariff Schedules 4E and 9E of the BPA Tariff.

Capitalized terms not otherwise defined by this section shall have the meaning set forth in the BPA Tariff.

A. Imbalance Charges – Tariff Schedules 4E And 9E

1. Energy Imbalance Service (Schedule 4E) (EIM)

A Transmission Customer shall be charged or paid for EI Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule (as determined pursuant to Section 4.2.4 of Attachment Q of the BPA Tariff) settled as UIE for the period of the deviation at the applicable Load Aggregation Point (LAP) price where the load is located as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

Transmission Customers taking EI Service shall be subject to the Persistent Deviation Penalty Charge for UIE pursuant to GRSP II.L.2.

2. Generation Imbalance Service (Schedule 9E) (EIM)

a. GI Service When No Schedule Changes Occur to Resource After T-57.

Except as provided for in Section 2.b. below, Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Transmission Customer's metered generation compared to the resource component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

b. GI Service When Changes Occur To Resource Schedule After T-57

For Transmission Customers that have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or if the scheduled output of a resource changes after T-57, the following provisions shall apply:

(1) GI – Uninstructed Imbalance Energy Charges/Credits

(A) UIE/RTD (Metered Gen - Scheduled Output at RTD)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Transmission Customer’s metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

Transmission Customers taking GI Service shall be subject to the Persistent Deviation Penalty Charge for UIE pursuant to GRSP II.L.1.

(2) GI – Instructed Imbalance Energy Charges/Credits

(A) FMM-IIE (Scheduled Output at FMM - TCBS)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in the FMM (FMM Schedule), compared to the resource component of the Transmission Customer Base Schedule, settled as IIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

(B) RTD-IIE (Scheduled Output at RTD –FMM)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in RTD, compared to the FMM Schedule, as IIE for the period of the deviation at the applicable PNode RTD price where

the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

(C) Intrachange Imbalance Adjustment.

If a Transmission Customer elects to receive Intrachange Imbalance pursuant to the BPA EIM Business Practice, then the FMM-IIE and RTD-IIE associated with such Intrachange shall be settled with the resource in accordance with Section IV.B.2 of this section.

B. Interchange And Intrachange Imbalance

1. Interchange Imbalance

Interchange Imbalance is assessed when deviations occur between the Interchange portion of a Transmission Customer's Base Schedule and the schedule value at the applicable Fifteen-Minute Market (FMM) or Real-Time Dispatch (RTD) market interval. Transmission Customers with Interchange Imbalance shall be assessed IIE at either the FMM Locational Marginal Price (LMP), the RTD LMP, or both, depending upon when the changes to the Transmission Customer's Interchange are incorporated by the MO into the applicable EIM market run. Interchange Imbalance shall be calculated as follows:

a. Calculation of Interchange Imbalance – FMM-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the Interchange portion of the Transmission Customer's Base Schedule compared to the Interchange schedule incorporated by the MO in the FMM (FMM Schedule). Such imbalance shall be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the Interchange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

b. Calculation of Interchange Imbalance – RTD-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the FMM Schedule compared to the Interchange schedule incorporated by the MO in the RTD. Such imbalance shall be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the Interchange is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

2. Intrachange Imbalance

Intrachange Imbalance is assessed when deviations occur between the Intrachange portion of a Transmission Customer's Base Schedule and the Transmission Customer's Intrachange schedule at an applicable FMM or RTD market interval. BPA will assess Intrachange Imbalance when requested by Power Services or a Transmission Customer and upon meeting the requirements in the BPA EIM Business Practice. Intrachange Imbalance shall be assessed IIE at either the FMM LMP, the RTD LMP, or both, depending

upon when the changes to the Transmission Customer's Intrachange occurs. Intrachange Imbalance shall be calculated as follows:

a. Calculation of Intrachange Imbalance - FMM-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the Intrachange portion of the Transmission Customer's Base Schedule compared to the Transmission Customer's Intrachange schedule at the applicable FMM interval (FMM Schedule). Such imbalance shall be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

b. Calculation of Intrachange Imbalance - RTD-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the FMM Schedule compared to the Transmission Customer's Intrachange schedule at the applicable RTD interval. Such imbalance shall be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

c. Adjustment to IIE Settlement for Source Resource Responsible for an Intrachange

The source resource responsible for an Intrachange shall be charged or paid an amount of Intrachange Imbalance that exactly offsets the Intrachange Imbalance paid or charged the Transmission Customer under Sections IV.B.2.a and b above.

d. Applicability to Interchange

Power Services or a Transmission Customer may elect to have an Interchange Imbalance settlement adjusted in the same manner as an Intrachange Imbalance by making such election pursuant to the BPA EIM Business Practice.

C. Charges For Under-Scheduling or Over-Scheduling Load

1. Under-Scheduling Load

Any charges to the BPA EIM entity pursuant to Section 29.11(d)(1) of the MO Tariff for underscheduling load shall be assigned to the Transmission Customers subject to Schedule 4 based on each Transmission Customer's respective under-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's under-scheduled load imbalance amount relative to all other Transmission Customers' under-scheduled load imbalance amounts who have under-scheduled load for the Operating Hour, expressed as a percentage.

2. Over-Scheduling Load

Any charges to the BPA EIM entity pursuant to Section 29.11(d)(2) of the MO Tariff for overscheduling load shall be assigned to the Transmission Customers subject to Schedule 4 based on each Transmission Customer's respective over-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's over-scheduled load imbalance amount relative to all other Transmission Customers' over-scheduled load imbalance amounts who have over-scheduled load for the Operating Hour, expressed as a percentage.

3. Distribution Of Under-Scheduling Or Over-Scheduling Proceeds

Any payment to the BPA EIM Entity pursuant to Section 29.11(d)(3) of the MO Tariff shall be distributed to Transmission Customers on the basis of EIM Metered Demand whose daily average absolute Schedule 4E UIE is less than 5 percent or 2 MW (whichever is greater) of its daily average schedule. For those Transmission Customers that qualify to receive proceeds, the proceeds shall be allocated based on a ratio of each Transmission Customer's daily average EIM Metered Demand relative to aggregate daily average EIM Metered Demand of all other Transmission Customers' who are eligible to receive proceeds for that day.

D. EIM Neutrality And Uplift Charges And Credits

1. EIM BAA Real-Time Market Neutrality (Real-Time Imbalance Energy Offset EIM)

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(3) of the MO Tariff for EIM BAA real-time market neutrality shall be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

2. EIM Entity BAA Real-Time Congestion Offset

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(2) of the MO Tariff for the EIM real-time congestion offset shall be allocated to Transmission Customers on the basis of EIM Measured Demand.

3. EIM Entity Real-time Marginal Cost of Losses Offset

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(4) of the MO Tariff for real-time marginal cost of losses offset shall be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

4. EIM Neutrality Settlement (Real-Time System Imbalance Energy Offset)

Any charges to the BPA EIM Entity pursuant to Section 29.11(e)(5) of the MO Tariff for EIM neutrality settlement shall be sub-allocated as follows:

Description	Allocation
Neutrality Adjustment (monthly and daily)	EIM Measured Demand
Rounding Adjustment (monthly and daily)	EIM Measured Demand

5. Real-Time Unaccounted For Eim Energy Settlement (UFE)

Any charges to the BPA EIM entity pursuant to Section 29.11(c) of the MO Tariff for UFE shall be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

E. Rolled In Charges

All other charges or credits assessed by the MO to the BPA EIM entity that are not otherwise allocated by this Section IV shall be rolled in and recovered through base Transmission rates.

F. Other Charges and Provisions

1. MO Tax Liabilities

Any charges to the BPA EIM entity pursuant to Section 29.22(a) of the MO Tariff for MO tax liability as a result of the EIM shall be sub-allocated to those Transmission Customers triggering the tax liability.

2. Market Validation and Price Correction

If the MO modifies the BPA EIM entity settlement statement in accordance with the MO's market validation and price correction procedures in the MO Tariff, the BPA EIM entity reserves the right to make corresponding or similar changes to the charges and payments suballocated under this Section IV.

SECTION V. 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 For Transmission Cost Recovery Adjustment Clause, Transmission Reserves Distribution Clause, and Transmission Financial Reserves Policy Surcharge

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), the Transmission Reserves Distribution Clause (RDC), and the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSPs II.G, II.H, and II.I.

GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

A. Approval Of Rates

BPA has requested that the Federal Energy Regulatory Commission (FERC) grant approval to make these rate schedules and GRSPs effective on October 1, 2021. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-22 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-20 rate schedules, which became effective October 1, 2019, 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-22 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 FERC'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. Billing Disputes

Any billing dispute must be initiated in accordance with and follow the dispute resolution procedures in Section 12 of the Tariff and any business practices implementing that section.

4. 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 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 FERC policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

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-22) Rate, Section III

b. Utility Delivery

\$1.655 per kilowatt (kW) 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.

3. Adjustments, Charges, and Other Rate Provisions

a. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

b. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause (RDC), specified in GRSP II.H.

c. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

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 kWh 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 Transmission Rates website 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 OATT 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 OATT 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. Waiver or Reduction of a Failure To Comply Penalty Charge

BPA may, in its sole discretion, waive or reduce a Failure to Comply Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction in a Failure to Comply Penalty Charge, a customer must submit a request demonstrating that the events resulting in a Failure to Comply Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Failure to Comply Penalty Charges in deciding whether to waive or reduce a Failure to Comply Penalty Charge.

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 non-refundable 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.

For each extension of the Service Commencement Date, the Reservation Fee is equal to one month's charge for the requested Long-Term Firm PTP Transmission Service. The Reservation Fee shall be specified in the executed Service Agreement.

E. Transmission and Ancillary Services Rate Discounts

BPA may offer discounted rates for transmission service and for ancillary services provided in conjunction with the provision of transmission service. Three principal requirements apply to discounts for transmission and ancillary services, 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 same segment of 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 PTP 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

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

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 website.

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 PTP 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. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

The Transmission CRAC is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

1. Transmission CRAC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Transmission Services (Transmission RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Transmission CRAC may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission CRAC Amount

The Transmission CRAC Threshold is an amount of Transmission RFR below which Transmission is considered to have experienced an underrun. The underrun amount is equal to the Transmission CRAC Threshold minus Transmission RFR.

The Transmission CRAC Amount is based on the underrun minus the Revenue Financing Amount, limited by the Maximum Transmission CRAC Recovery Amount (the Transmission CRAC Cap). There are three possibilities:

- (1) If the underrun minus the Revenue Financing Amount is less than \$5 million, there is no Transmission CRAC.
- (2) If the underrun minus the Revenue Financing Amount is greater than or equal to \$5 million and less than or equal to \$100 million, the Transmission CRAC Amount is equal to the underrun minus the Revenue Financing Amount.
- (3) If the underrun minus the Revenue Financing Amount is greater than or equal to \$100 million, the Transmission CRAC Amount is equal to \$100 million.

The Transmission CRAC Cap and Thresholds are shown in Table A.

Table A
Transmission CRAC Annual Thresholds and Caps
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2021	2022	\$0	\$40	\$100
2022	2023	\$0	\$40	\$100

b. Converting the Transmission CRAC Amount to the Transmission CRAC Percentage and Calculating Revised Rates

The Transmission CRAC Percentage is calculated by dividing the Transmission CRAC Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10 month period of December through September of the applicable year.

The Transmission CRAC Percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission CRAC Notification Process

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission CRAC Amount.

b. Notification of Transmission CRAC Trigger

By November 30, 2021, BPA will complete the calculation of Transmission RFR as of the end of FY 2021, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA will complete the calculation of Transmission RFR as of the end of FY 2022, for use in

calculating the Transmission CRAC applicable to rates for December through September of FY 2023.

If the Transmission CRAC triggers, BPA will notify customers of the preliminary Transmission CRAC Amount to be recovered by the Transmission CRAC Percentage for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Transmission CRAC Percentage.

BPA will hold at least one public meeting to discuss the calculations of Transmission RFR, the Transmission CRAC Amount, and the Transmission CRAC Percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission CRAC Amount and the Transmission CRAC Percentage as soon as practicable, but in no case later than December 15 of each applicable year.

H. Transmission Reserves Distribution Clause (Transmission RDC)

The Transmission RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Transmission RDC is calculated each fiscal year.

If the Transmission RDC quantitative criteria (below) are met, the Administrator will calculate the Transmission RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Transmission Dividend Distribution (Transmission DD), distributions to customers, or any other Transmission-specific purposes determined by the Administrator.

A Transmission DD is a downward adjustment that applies to these Transmission rates:

- Network Integration Rate (NT-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

1. Transmission RDC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Transmission Services (Transmission RFR) and financial reserves available for risk that are attributed to BPA (BPA RFR) as of the fiscal year preceding the applicable year. If Transmission RFR is greater than the Transmission RDC Threshold for that applicable year by at least \$5 million, and BPA RFR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine the Transmission RDC Amount. If the Administrator determines that all or part of the Transmission RDC Amount will be applied to a Transmission DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission RDC Amount

The Transmission RDC can trigger only if (1) Transmission RFR exceeds the Transmission RDC Threshold and (2) BPA RFR exceeds the BPA RDC Threshold.

The Transmission RDC Amount is the amount of Transmission RFR that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a Transmission DD, distribute to customers, or any other Transmission-specific purposes determined by the Administrator. The Transmission RDC Amount will be the smallest of Transmission RFR minus the Transmission RDC Threshold, BPA RFR minus the BPA RDC Threshold, or the Transmission RDC Cap.

**Table B
Transmission RDC Annual Thresholds and Caps
(dollars in millions)**

Transmission RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Transmission RFR Threshold	Maximum RDC Amount (Cap)
2021	2022	\$204	\$200
2022	2023	\$204	\$200

**Table C
BPA RDC Annual Thresholds
(dollars in millions)**

BPA RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	BPA RFR Threshold
2021	2022	\$605
2022	2023	\$605

b. Converting a Transmission DD to the Transmission DD Percentage and Calculating Revised Rates

The Transmission DD Credit Percentage is calculated by dividing the Transmission DD Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10 month period of December through September of the applicable year.

The Transmission DD Credit Percentage is subtracted from 1.0 and then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission RDC Notification Process

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission RDC Amount.

b. Notification of Transmission RDC Trigger

By November 30, 2021, BPA shall complete the calculation of Transmission RFR and BPA RFR as of the end of FY 2021, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Transmission RFR and BPA RFR as of the end of FY 2022, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2023.

If the Transmission RDC triggers, BPA will notify customers of the preliminary Transmission RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Transmission purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Transmission RDC Amount.

BPA will hold at least one public meeting to discuss the calculations of Transmission RFR, the Transmission RDC Amount, and if applicable, the Transmission DD Credit Amount and the Transmission DD Credit percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission RDC amount as soon as practicable, but in no case later than December 15 of each applicable year.

I. Transmission Financial Reserves Policy Surcharge (Transmission FRP Surcharge)

The Transmission FRP Surcharge is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

1. Transmission FRP Surcharge Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate financial reserves available for risk that are attributed to Transmission Services (Transmission RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Transmission FRP Surcharge may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission FRP Surcharge Amount

The Transmission FRP Surcharge Threshold is an amount of Transmission RFR, below which Transmission is considered to have experienced an underrun. The underrun amount is equal to the Transmission FRP Surcharge Threshold minus Transmission RFR.

The Transmission FRP Surcharge Amount is based on the underrun minus the Revenue Financing Amount, limited by the Base Surcharge. There are three possibilities:

- (1) If the underrun minus the Revenue Financing Amount is less than \$5 million, there is no Transmission FRP Surcharge.
- (2) If the underrun minus the Revenue Financing Amount is greater than or equal to \$5 million and less than or equal to the Base Surcharge, the Transmission FRP Surcharge Amount is equal to the underrun minus the Revenue Financing Amount.

- (3) If the underrun minus the Revenue Financing Amount is greater than or equal to the Base Surcharge, the FRP Surcharge Amount is equal to the Base Surcharge.

The Transmission FRP Surcharge Thresholds and Base Surcharge are shown in Table D.

Table D
Transmission FRP Surcharge Annual Thresholds and Caps
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Base Surcharge
2021	2022	\$102	\$40	\$15
2022	2023	\$102	\$40	\$15

b. Converting the Transmission FRP Surcharge Amount to the Transmission FRP Surcharge Percentage and Calculating Revised Rates

The Transmission FRP Surcharge Percentage is calculated by dividing the Transmission FRP Surcharge Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10 month period of December through September of the applicable year.

The Transmission FRP Surcharge Percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission FRP Surcharge Notification Process

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission FRP Surcharge Amount.

b. Notification of Transmission FRP Surcharge

By November 30, 2021, BPA shall complete the calculation of Transmission RFR as of the end of FY 2021, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Transmission RFR as of the end of FY 2022, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2023.

If the Transmission FRP Surcharge triggers, BPA will notify customers of the preliminary Transmission FRP Surcharge Amount to be recovered by the Transmission FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge.

BPA will hold at least one public meeting to discuss the calculations of Transmission RFR, the Transmission FRP Surcharge Amount, and the Transmission FRP Surcharge percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission FRP Surcharge Amount and the Transmission FRP Surcharge percentage as soon as practicable, but in no case later than December 15 of each applicable year.

J. Financial for Inaccuracy Penalty Charge

The Financial for Inaccuracy Penalty Charge (FFI Penalty Charge) applies to a Transmission Customer that elects In-Kind Loss Return Service when the Customer returns a different amount of power than its real power loss obligation or does not timely settle its loss obligation.

1. Rates

a. Energy Price

The Energy Price for the FFI Penalty Charge will differ depending on whether BPA is a participant in the Western EIM.

(1) Energy Price when BPA is not an EIM Participant

If BPA is not a participant in the EIM, then the Energy Price will be the applicable average hourly Powerdex Mid-C Index price for firm power for the hour in which the loss occurred. In the event the hourly Powerdex Mid-C price index is no longer a reliable price index, the index will be replaced by an applicable new hourly energy index at a hub at which Northwest parties can trade between October 1, 2021, and September 30, 2023. BPA will provide notice of such a change as soon as practicable.

(2) Energy Price when BPA is an EIM Participant

If BPA is a participant in the EIM, then the Energy Price will be the applicable hourly average Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred.

b. Under-Delivery Event (UDE)

For each hour that the Transmission Customer returns less energy than its real power loss obligation, the FFI penalty rates shall be:

- (1) UDE Capacity Rate: 5.58 mills per kilowatthour
- (2) UDE Energy Rate: the greater of \$0 or 250 percent of the Energy Price.

c. Over-Delivery Event (ODE)

For each hour that the Transmission Customer returns more energy than its real power loss obligation, the FFI penalty rates shall be:

- (1) ODE Capacity Rate: 5.58 mills per kilowatthour
- (2) ODE Energy Rate: 250 percent of the absolute value of the Energy Price

The ODE Energy Rate shall not be assessed when the Transmission Customer returns more energy than its real power loss obligation and the Energy Price is equal to or greater than \$0 per MWh.

2. Billing Factors

a. Under Delivery Event

The Billing Factor (in kWh) for the UDE rates shall be for each hour:

Customer's Real Power Loss Obligation

Minus

The quantity of loss returns provided by the customer.

b. Over Delivery Event

The Billing Factor (in kWh) for the ODE rates shall be for each hour:

The quantity of loss returns provided by the customer

Minus

Customer's Real Power Loss Obligation

3. Other Provisions

BPA will exempt a Transmission Customer from the FFI Penalty Charge during times of BAA or Transmission Provider reliability adjustments to real power loss returns.

4. Waiver or Reduction of Charge

BPA may, in its sole discretion, waive or reduce an FFI Penalty Charge if requested by the Transmission Customer for good cause shown. In order to qualify for a waiver or reduction of an FFI Penalty Charge, the Transmission Customer must submit a request demonstrating that the events resulting in the charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the Transmission Customer's history of incurring FFI Penalty Charges in deciding whether to waive or reduce a charge.

K. 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-22 VERBS rate.

Exceptions:

- a. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

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:

$$ABS(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) > 1$$

(See Section 3, below, for definition of terms.)

3. Billing Factor

The Billing Factor in MWh shall be:

$$ABS(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) - 1$$

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

- 1) for wind generating customers taking VERBS under rate schedule Section 2.a., the applicable schedule value provided by BPA;
- 2) for solar generating customers taking VERBS under rate schedule Section 2.b., the applicable 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 integrated over the hour.

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

$$ABS(\text{Station Control Error}) \leq ABS(\text{Intentional Deviation Measurement Value Error}) + 1 \text{ MW}$$

Where:

$ABS(\text{Intentional Deviation Measurement Value Error})$ = 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. Any interval in which a Variable Energy Resource that is a Participating Resource in the EIM receives an instructed dispatch from the Market Operator is excluded from the calculation of Station Control Error and Intentional Deviation Measurement Value Error.

5. Waiver or Reduction of Intentional Deviation Penalty Charge

BPA may, in its sole discretion, waive or reduce an Intentional Deviation Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction of an Intentional Deviation Penalty Charge, a customer must submit a request demonstrating that the events resulting in an Intentional Deviation Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Intentional Deviation Penalty Charge in deciding whether to waive or reduce an Intentional Deviation Penalty Charge.

L. Persistent Deviation Penalty Charge

1. Dispatchable Energy Resource Balancing Service

a. Applicability

For Dispatchable Energy Resources taking DERBS pursuant to ACS III.F, the Persistent Deviation Penalty Charge applies to 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 integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;
- (2) both 7.5 percent of the integrated hourly 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 integrated hourly schedule and 5 MW in each scheduled period for 12 consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

When BPA is in the EIM, positive or negative deviations will be based on the measurement value used for determining UIE.

b. Rate

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 either BPA's highest incremental cost that occurs during that day for service under ACS III.B, or the highest LMP at the closest point of interconnection during the period of penalty for service under ACS IV.A.2, or (ii) 100 mills per kilowatthour. For Participating Resources in the EIM the charge is the greater of (i) 25 percent of the highest LMP at the closest point of interconnection during the period of penalty, or (ii) 100 mills per

kilowatthour minus the highest LMP at the closest point of interconnection during the period of penalty.

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 ACS II.B or ACS.IV.B.2.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

2. Energy Imbalance Service

a. Applicability

For customers taking EI Service pursuant to ACS II.D and IV.A.1, the Persistent Deviation Penalty Charge applies to 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 integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;
- (2) both 7.5 percent of the integrated hourly 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 integrated hourly schedule and 5 MW in each scheduled period for 12 consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

For EI Service pursuant to ACS IV.B.1, positive or negative deviations will be based on the measurement value used for determining UIE pursuant to that section.

b. Rate

No credit is given when energy taken is less than the scheduled energy.

When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS II.D, or the highest LAP during the period of penalty for service under ACS IV.B.1, 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 ACS II.D or IV.B.1.

3. Pattern Of Conduct

A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day. For GI Service, the rate under Section 1.b above shall apply, and for EI Service, the rate under Section 2.b above shall apply.

4. 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.

M. Modified Tier 1 Cost Allocators (TOCA) for Oversupply Rate

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2022	FY 2023
10005	Alder Mutual	0.0000818	0.0000815
10015	Asotin County PUD #1	0.0000856	0.0000853
10024	Benton County PUD #1	0.0300310	0.0299330
10025	Benton REA	0.0089011	0.0088721
10027	Big Bend Elec Coop	0.0091302	0.0091004
10029	Blachly Lane Elec Coop	0.0026283	0.0026197
10044	Canby, City of	0.0030302	0.0030203
10046	Central Electric Coop	0.0122122	0.0121723
10047	Central Lincoln PUD	0.0233756	0.0232993
10055	Albion, City of	0.0000594	0.0000592
10057	Ashland, City of	0.0031245	0.0031143
10059	Bandon, City of	0.0011397	0.0011360
10061	Blaine, City of	0.0013049	0.0013007
10062	Bonnors Ferry, City of	0.0007936	0.0007910
10064	Burley, City of	0.0020984	0.0020916
10065	Cascade Locks, City of	0.0003548	0.0003536
10066	Centralia, City of	0.0036362	0.0036243
10067	Cheney, City of	0.0023599	0.0023522
10068	Chewelah, City of	0.0004049	0.0004044
10070	Declo, City of	0.0000535	0.0000534
10071	Drain, City of	0.0002856	0.0002847
10072	Ellensburg, City of	0.0035782	0.0035665
10074	Forest Grove, City of	0.0039810	0.0039680
10076	Heyburn, City of	0.0007187	0.0007163
10078	McCleary, City of	0.0005546	0.0005528
10079	McMinnville, City of	0.0127012	0.0126925
10080	Milton, Town of	0.0010730	0.0010699
10081	Milton-Freewater, City of	0.0014425	0.0014380
10082	Minidoka, City of	0.0000149	0.0000148
10083	Monmouth, City of	0.0012478	0.0012438
10086	Plummer, City of	0.0005886	0.0005866
10087	Port Angeles, City of	0.0088007	0.0087720
10089	Richland, City of	0.0154954	0.0154449
10091	Rupert, City of	0.0014059	0.0014013
10094	Soda Springs, City of	0.0004532	0.0004517
10095	Sumas, Town of	0.0005436	0.0005418
10097	Troy, City of	0.0003041	0.0003031
10101	Clallam County PUD #1	0.0113434	0.0113063

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2022	FY 2023
10103	Clark County PUD #1	0.0475194	0.0473643
10105	Clatskanie PUD	0.0129637	0.0129768
10106	Clearwater Power	0.0035628	0.0035511
10109	Columbia Basin Elec Coop	0.0018081	0.0018022
10111	Columbia Power Coop	0.0004771	0.0004752
10112	Columbia River PUD	0.0086146	0.0086032
10113	Columbia REA	0.0056238	0.0056054
10116	Consolidated Irrigation District #19	0.0000339	0.0000338
10118	Consumers Power	0.0068145	0.0067923
10121	Coos Curry Elec Coop	0.0060856	0.0060657
10123	Cowlitz County PUD #1	0.0709606	0.0743588
10136	Douglas Electric Cooperative	0.0027658	0.0027568
10142	East End Mutual Electric	0.0004009	0.0003996
10144	Eatonville, City of	0.0005026	0.0005009
10156	Elmhurst Mutual P & L	0.0048100	0.0047943
10157	Emerald PUD	0.0074537	0.0074294
10158	Energy Northwest	0.0003712	0.0003700
10170	Eugene Water & Electric Board	0.0355022	0.0355585
10172	U.S. Airforce Base, Fairchild	0.0008556	0.0008548
10173	Fall River Elec Coop	0.0049430	0.0049269
10174	Farmers Elec Coop	0.0000757	0.0000754
10177	Ferry County PUD #1	0.0013931	0.0013918
10179	Flathead Elec Coop	0.0248899	0.0248086
10183	Franklin County PUD #1	0.0175089	0.0174518
10186	Glacier Elec Coop	0.0028391	0.0028468
10190	Grant County PUD #2	0.0007745	0.0007720
10191	Grays Harbor PUD #1	0.0195776	0.0195137
10197	Harney Elec Coop	0.0033947	0.0033836
10202	Hood River Elec Coop	0.0019544	0.0019480
10203	Idaho County L & P	0.0009271	0.0009241
10204	Idaho Falls Power	0.0098567	0.0098313
10209	Inland P & L	0.0156497	0.0155986
10230	Kittitas County PUD #1	0.0014476	0.0014429
10231	Klickitat County PUD #1	0.0054695	0.0054517
10234	Kootenai Electric Coop	0.0076091	0.0075842
10235	Lakeview L & P (WA)	0.0047981	0.0048062
10236	Lane County Elec Coop	0.0042825	0.0042685
10237	Lewis County PUD #1	0.0164117	0.0163581
10239	Lincoln Elec Coop (MT)	0.0020888	0.0020820
10242	Lost River Elec Coop	0.0014213	0.0014166

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2022	FY 2023
10244	Lower Valley Energy	0.0128368	0.0127949
10246	Mason County PUD #1	0.0013409	0.0013365
10247	Mason County PUD #3	0.0119254	0.0118865
10256	Midstate Elec Coop	0.0069744	0.0069517
10258	Mission Valley	0.0056624	0.0056439
10259	Missoula Elec Coop	0.0040262	0.0040130
10260	Modern Elec Coop	0.0039216	0.0039088
10273	Nespelem Valley Elec Coop	0.0008775	0.0008746
10278	Northern Lights	0.0053605	0.0053430
10279	Northern Wasco County PUD	0.0096629	0.0096314
10284	Ohop Mutual Light Company	0.0015157	0.0015107
10285	Okanogan County Elec Coop	0.0009741	0.0009709
10286	Okanogan County PUD #1	0.0068500	0.0068277
10288	Orcas P & L	0.0036904	0.0036783
10291	Oregon Trail Coop	0.0118140	0.0117755
10294	Pacific County PUD #2	0.0054199	0.0054022
10304	Parkland L & W	0.0020937	0.0020919
10306	Pend Oreille County PUD #1	0.0000000	0.0000000
10307	Peninsula Light Company	0.0106564	0.0106325
10326	U.S. Naval Base, Bremerton	0.0045445	0.0045297
10331	Raft River Elec Coop	0.0054611	0.0054433
10333	Ravalli County Elec Coop	0.0027623	0.0027533
10338	Riverside Elec Coop	0.0003539	0.0003528
10342	Salem Elec Coop	0.0057727	0.0057538
10343	Salmon River Elec Coop	0.0018795	0.0018733
10349	Seattle City Light	0.0673546	0.0669282
10352	Skamania County PUD #1	0.0023732	0.0023655
10354	Snohomish County PUD #1	0.1103917	0.1092978
10360	Southside Elec Lines	0.0010093	0.0010060
10363	Springfield Utility Board	0.0142516	0.0142402
10369	Surprise Valley Elec Coop	0.0024516	0.0024436
10370	Tacoma Public Utilities	0.0566432	0.0566379
10371	Tanner Elec Coop	0.0016461	0.0016407
10376	Tillamook PUD #1	0.0083596	0.0083323
10378	Coulee Dam, City of	0.0002939	0.0002935
10379	Steilacoom, Town of	0.0007112	0.0007123
10388	Umatilla Elec Coop	0.0168930	0.0168378
10391	United Electric Coop	0.0044726	0.0044580
10406	U.S. DOE Albany Research Center	0.0000684	0.0000682
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002279	0.0002272

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2022	FY 2023
10409	U.S. Naval Submarine Base, Bangor	0.0030469	0.0030370
10426	U.S. DOE Richland Operations Office	0.0025623	0.0025540
10434	Vera Irrigation District	0.0040518	0.0040385
10436	Vigilante Elec Coop	0.0028575	0.0028481
10440	Wahkiakum County PUD #1	0.0007468	0.0007444
10442	Wasco Elec Coop	0.0019897	0.0019832
10446	Wells Rural Elec Coop	0.0142890	0.0142424
10448	West Oregon Elec Coop	0.0012653	0.0012612
10451	Whatcom County PUD #1	0.0040035	0.0039904
10482	Umpqua Indian Utility Cooperative	0.0004388	0.0004374
10502	Yakama Power	0.0027912	0.0027821
13927	Kalispel Tribe Utility	0.0005914	0.0005969
10597	Hermiston, City of	0.0019250	0.0019198
10706	Port of Seattle - SETAC In'tl. Airport	0.0025779	0.0025695
11680	Weiser, City of	0.0009443	0.0009412
12026	Jefferson County PUD #1	0.0067399	0.0067179
10007	Alcoa	0.0000000	0.0000000
10312	Port Townsend Paper	0.0018769	0.0018708
10298	PNGC Aggregate	0.0648972	0.0646854

SECTION III. DEFINITIONS

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. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

11. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. 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.

13. EIM Measured Demand

Includes (1) EIM Metered Demand, plus (2) e-Tagged export volumes from the BPA BAA (excluding EIM Transfers).

14. EIM Metered Demand

Metered load volumes in BPA's BAA.

15. 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.

16. 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.

17. 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.

18. Fifteen Minute Market (FMM)

The definition of FMM is provided in the MO Tariff.

19. 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.

20. 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.

21. 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.

22. 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.

23. 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.

24. Instructed Imbalance Energy (IIE)

A type of Imbalance Energy that occurs when changes are made to a resource, Interchange, or (if applicable) Intrachange schedule after the submission of the financially binding Transmission Customer Base Schedule. IIE will be settled at either the Fifteen Minute Market (FMM) or Real-Time Dispatch (RTD) price at the applicable Price Node (PNode) depending on the nature and timing of the imbalance.

25. 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.

26. Load Aggregation Point (LAP)

The LAP is a set of Pricing Nodes that is used for the submission of bids and settlement of demand in the EIM.

27. Locational Marginal Price (LMP)

The marginal cost (\$/MWh) of serving the next increment of demand at that PNode consistent with existing transmission constraints and the performance characteristics of resources.

28. 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.

29. 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.

30. 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.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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.

36. Montana Intertie

The Montana Intertie is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

37. Monthly Services

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.

38. 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.

39. 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).

40. Network Integration Transmission (NT) Service

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

41. 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.

42. 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.

43. 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.

44. 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.

45. 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.

46. 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.

47. 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.

48. 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.

49. 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.”

50. 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.

51. Pricing Node (PNode)

A single network node or subset of network nodes where a physical injection or withdrawal is modeled by the MO and for which the MO calculates an LMP that is used for financial settlements by the MO and the BPA EIM Entity.

52. 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.

53. 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.

54. 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.

55. Real-Time Dispatch (RTD)

The definition of RTD is provided in the MO Tariff.

56. 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.

57. 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.

58. 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.

59. Scheduled Demand

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

60. 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.

61. 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.

62. 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.

63. 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.

64. 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.

65. Secondary Transformation

As used in the FPT rate schedules, Secondary Transformation refers to transformation from Main Grid to Secondary System facilities.

66. 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.

67. 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.

68. 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.

69. 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.

70. 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.

71. 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.

72. 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.

73. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

74. 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.

75. 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.

76. 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.

77. 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.

78. 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.

79. 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.

