

BP-26 Rate Proceeding

Final Proposal

# Power Rates Study

BP-26-FS-BPA-01

July 2025





# POWER RATES STUDY

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## COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
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
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission (see also “FERC”)
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)
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
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
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
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council (see also "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
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)
P10	tenth percentile of a given dataset
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)
RAS	Remedial Action Scheme
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
RRHL	Regional Residual Hydro Load
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
SCADA	Supervisory Control and Data Acquisition
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
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
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

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# 1. INTRODUCTION AND BACKGROUND

## 1.1 Power Rates Study Overview

This Power Rates Study (PRS or Study) explains the processes and calculations used to develop the power rates and Billing Determinants for Bonneville Power Administration's (BPA) wholesale power products and services. The PRS serves three primary purposes: 1) to demonstrate that rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute, 2) to set rates consistent with BPA policies, and 3) to demonstrate that rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period, fiscal years (FY) 2026, 2027 and 2028.

The development of rates in the PRS uses inputs from a variety of sources:

- The Power Revenue Requirement Study, BP-26-FS-BPA-02, and its accompanying Documentation, BP-26-FS-BPA-02A, provides information regarding the power revenue requirement. *See* Power Revenue Requirement Study, § 2.5.
- The Power Loads and Resources Study, BP-26-FS-BPA-03, and its accompanying Documentation, BP-26-FS-BPA-03A, provide load and resource forecasts.
- The Power Market Price Study and Documentation, BP-26-FS-BPA-04, provides electricity market price forecasts. The market price forecasts are used in the development of demand rates, load shaping rates, short-term balancing purchases and expenses, augmentation purchases and expenses, secondary energy sales and revenue, and Planned Net Revenues for Risk (PNRR), if any.
- The Power and Transmission Risk Study, BP-26-FS-BPA-05, and its accompanying Documentation, BP-26-FS-BPA-05A, provide forecast quantities of power expected to be sold and purchased in electric markets and demonstrate that the rates and risk

1 mitigation tools together meet BPA’s standard for financial risk tolerance—the  
2 92.3 percent three-year equivalent of BPA’s two-year Treasury Payment Probability  
3 (TPP) standard of 95 percent. The Risk Study includes quantitative and qualitative  
4 analyses of financial risks and tools for mitigating those risks, including those  
5 required by BPA’s Financial Reserves Policy (FRP). *See* Administrator’s Record of  
6 Decision, Financial Reserves Policy Phase-In Implementation, Appendix 1.

7  
8 Power Services receives revenue from the generation inputs it provides to Transmission  
9 Services. The amount of the anticipated revenues from balancing services and other power  
10 services provided to Transmission customers is specified in the Power Rates Study  
11 Documentation, BP-26-FS-BPA-01A, Table 9.3.

12  
13 The revenues resulting from the rates developed in the PRS are used by the Power Revenue  
14 Requirement Study in the Revised Revenue Test to test the adequacy of rates to recover  
15 expenses and supply adequate cash to cover non-expense cash outlays. *See* Power Revenue  
16 Requirement Study, BP-26-FS-BPA-02, § 3.3.

## 17 18 **1.2 Statutory and Legal Overview**

19 The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power  
20 Act), 16 U.S.C. § 839, is the primary statute providing ratemaking directives to BPA. The  
21 Northwest Power Act’s Section 7(a)(1), 16 U.S.C. § 839e(a)(1), states:

22 The Administrator shall establish, and periodically review and revise, rates for  
23 the sale and disposition of electric energy and capacity and for the  
24 transmission of non-Federal power. Such rates shall be established and, as  
25 appropriate, revised to recover, in accordance with sound business principles,  
26 the costs associated with the acquisition, conservation, and transmission of  
27 electric power, including the amortization of the Federal investment in the  
28 Federal Columbia River Power System (including irrigation costs required to  
29 be repaid out of power revenues) over a reasonable period of years and the

1 other costs and expenses incurred by the Administrator pursuant to this  
2 chapter and other provisions of law.

3  
4 The Bonneville Project Act defines “periodically review and revise” as revision of power  
5 and transmission rates not less frequently than once in every five years. 16 U.S.C.  
6 § 832d(a). Rates also are to be set in accordance with two other statutes: the Federal  
7 Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. § 838, and  
8 the Flood Control Act of 1944, 16 U.S.C. § 825s.

9  
10 Section 7 of the Northwest Power Act governs the allocation of BPA’s costs, which is  
11 performed in a cost of service analysis, as described in Section 2.1 below, and establishes a  
12 set of rate directives that provide further guidance on how individual rates are to be  
13 derived, as described in Section 2.2 below. *See* 16 U.S.C. § 839e(b).

### 14 15 **1.3 Regional Dialogue Policy Overview**

16 In the Long-Term Regional Dialogue Policy, issued in July 2007, BPA defined its power  
17 supply and marketing role for the long term. Key components of the policy include 20-year  
18 power sales contracts and a tiered Priority Firm Power rate construct that provides each  
19 preference customer with a Contract High Water Mark (CHWM). Each customer’s CHWM  
20 defines the amount of power the customer has a right to buy at a Tier 1 rate. Any power a  
21 utility chooses to buy from BPA for its load in excess of its CHWM is priced at a Tier 2 rate  
22 that is designed to recover the marginal cost of serving this additional load.

23  
24 BPA offered CHWM contracts to all of its preference and investor-owned utility (IOU)  
25 customers. Currently, these power service contracts are in effect for these customers for  
26 FY 2012-2028.

1 **1.3.1 Regional Dialogue Contract Product Descriptions**

2 Below is a brief summary of the products offered under BPA’s CHWM contracts. See BPA’s  
3 *Regional Dialogue Guidebook*, available in the Regional Dialogue Policy Implementation  
4 section of BPA’s website, [www.bpa.gov](http://www.bpa.gov), for full product descriptions and additional details  
5 on the interactions of the products, Tier 2 rate service, and Resource Support Services.

6  
7 **Load Following.** The Load Following product supplies firm power to meet a preference  
8 customer’s Total Retail Load (TRL), less any firm power supplied by the customer from any  
9 Dedicated Resources, including “behind the meter” non-federal resource amounts. The  
10 costs associated with the energy and capacity necessary to provide the Load Following  
11 service are recovered through Tier 1 rate charges for energy and demand.

12  
13 **Block.** The Block product provides a planned amount of firm power to meet a preference  
14 customer’s planned annual net requirement load. To buy this product, the customer must  
15 have dedicated non-federal resources, and the customer is responsible for using those  
16 resources dedicated to its TRL to meet any load in excess of its planned monthly BPA Block  
17 purchase. The costs associated with the energy and capacity necessary to provide this  
18 service are recovered through Tier 1 rate charges for energy and demand.

19  
20 **Slice/Block.** The Slice/Block product provides a combined sale of two distinct power  
21 products: 1) firm power for a preference customer’s net requirements load and an advance  
22 sale of surplus energy based on the generation shape of the federal system; and 2) firm  
23 requirements power under a Block product. The costs associated with the energy and  
24 capacity necessary to provide this service are recovered through Tier 1 rate charges for  
25 energy and demand.

1 **1.4 Tiered Rate Methodology**

2 The CHWM contracts and the Tiered Rate Methodology (TRM) provide long-term certainty  
3 to preference customers regarding their access to Tier 1 rate power and to BPA regarding  
4 its obligation to serve its preference customers' loads. *See* 2012 Wholesale Power and  
5 Transmission Rate Adjustment Proceeding (BP-12), Tiered Rate Methodology, BP-12-A-03.

6  
7 The TRM provides for a two-tiered Priority Firm Public (PFp) rate design applicable to firm  
8 requirements power service for preference customers that signed CHWM contracts. The  
9 TRM established a predictable and durable means to calculate BPA's PF tiered rates for  
10 power deliveries beginning in FY 2012. The tiered rate design differentiates between the  
11 cost of service associated with Tier 1 system resources and the cost associated with  
12 additional amounts of power sold by BPA to serve any remaining portion of a customer's  
13 net requirement, also referred to as Above-Rate Period High Water Mark (Above-RHWM)  
14 load. The tiering of the PFp rate is one of the final steps in the development of rates and  
15 does not alter the fundamental manner in which BPA allocates costs to the various rate  
16 pools under the Northwest Power Act. Section 3.2 describes the steps taken to tier the  
17 PFp rate.

18  
19 CHWMs, determined according to the TRM, help determine how much of each customer's  
20 net requirement purchased from BPA is charged at Tier 1 rates and how much may be  
21 charged at Tier 2 rates. The CHWM for each customer was calculated by BPA in FY 2011  
22 based on the expected output of Tier 1 system resources during FY 2012-2013 and  
23 customers' actual FY 2010 loads. The individual utility CHWMs set each customer's initial  
24 eligibility to purchase power at Tier 1 rates and became part of each utility's CHWM  
25 contract.

1 **1.4.1 Rate Period High Water Marks**

2 Related to the CHWM and also defined in the TRM is the Rate Period High Water Mark  
3 (RHWM), which is an expression of the CHWM scaled to the expected output of resources  
4 identified as comprising the Tier 1 system for the relevant rate period. Each customer’s  
5 RHWM for FY 2026-2028 defines that customer’s maximum eligibility to purchase at Tier 1  
6 rates for the rate period, limited for Slice and Block customers by the purchaser’s Annual  
7 Net Requirement and for Load Following customers by the purchaser’s Actual Net  
8 Requirement. The TRM specifies how rates will be developed to ensure, to the maximum  
9 extent possible, that customers’ purchases of power at Tier 1 rates do not pay any of the  
10 costs of serving Above-RHWM Load.

11  
12 To meet its Above-RHWM Load, a customer may purchase federal power, non-federal  
13 power, or a combination of the two. To the extent a customer purchases federal power for  
14 its Above-RHWM Load, a PF Tier 2 rate(s) will be applied to this portion of its federal  
15 power service. See Section 4.1.2 below.

16  
17 **1.4.2 Rate Period High Water Mark Process**

18 The RHWM is determined based on the customer’s CHWM and the RHWM Tier 1 System  
19 Capability (RT1SC) for each applicable rate period. The determination of a customer’s  
20 RHWM occurs outside of the rate proceeding in the RHWM Process, as described in  
21 TRM § 4.2.1.

22  
23 The RHWM Process for the FY 2026-2028 rate period was completed in September 2024.  
24 BPA engaged customers in a public process from June to September 2024, with two public  
25 comment periods and two public workshops. After completion of the review and comment  
26 periods, BPA examined the information collected. BPA posted its determination of values

1 for the FY 2026-2028 rate period for RHWMTier 1 System Capability, including RHWMTier  
2 Augmentation; each customer’s RHWMTier; and each customer’s Above-RHWMTier Load. See Rate  
3 Period High Water Mark Process, [https://www.bpa.gov/energy-and-services/rate-and-  
4 tariff-proceedings/rate-period-high-water-mark-process](https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/rate-period-high-water-mark-process); PRS Table 1.

5  
6 Once established, RHWMTiers are, under most circumstances, not changed. Exceptions include  
7 certain changes on a customer’s system, including annexation that results in a gain or loss  
8 of service territory or a later discovery that a load is a New Large Single Load (NLSL).

### 9 10 **1.5 Overview**

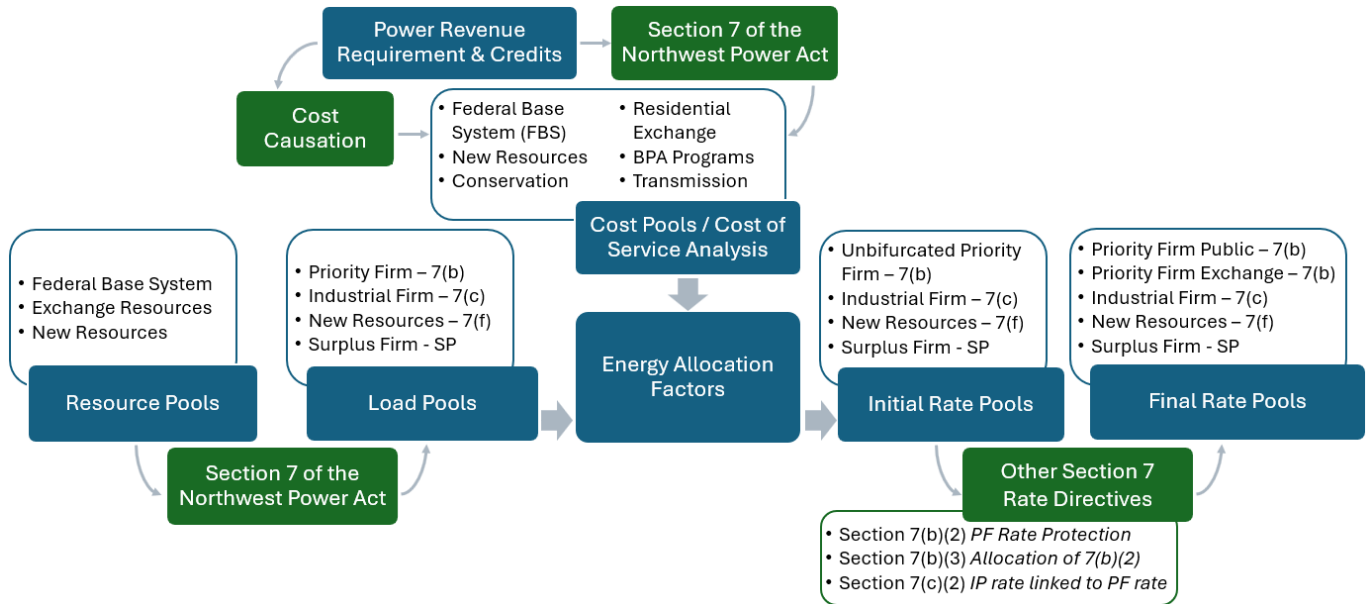
11 The next two sections discuss the ratemaking methodology and process, which result in the  
12 rate schedules and General Rate Schedule Provisions (GRSPs) discussed in Sections 4 and 5.

13 At a high level, BPA’s ratemaking process for power products and services has three main  
14 steps:

- 15 1. A Cost of Service Analysis (COSA) Step (Section 2.1), which allocates the various  
16 types of costs (categorized into resource or cost pools) to the various classes of  
17 customers (categorized into load or rate pools) using energy allocation factors  
18 calculated based on loads and resources.
- 19 2. A Rate Directives Step (Section 2.2), which reallocates costs between rate pools  
20 to ensure that the relationships between the rates for the different classes of  
21 customers comport with the rate directives in the Northwest Power Act.
- 22 3. A Rate Design Step (Section 3), which produces tiered PFp rates that collect the  
23 PFp revenue requirement determined in the Rate Directives Step. This step also  
24 implements the rate design for the non-tiered rates.

1 BPA's ratemaking processing for power products and services is depicted in Figure 1  
 2 below.

3 **Figure 1. BPA Ratemaking Process for Power Products and Services**



4  
 5  
 6 As noted above, Sections 4 and 5 discuss rate schedules and GRSPs resulting from these  
 7 steps. Section 6 discusses Transfer Service. More than half of BPA's power customers are  
 8 served by the transmission systems of third parties (entities other than BPA). Under the  
 9 Regional Dialogue contracts, BPA must acquire transmission services from these third-  
 10 party transmission providers to deliver federal power to BPA's power customers. This  
 11 third-party transmission service is commonly referred to as Transfer Service. Transfer  
 12 Service customers may be subject to one or more separate charges from BPA.

13  
 14 Section 7 discusses the Slice True-Up. Slice customers are subject to an annual Slice  
 15 True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the  
 16 Composite cost pool and to the Slice cost pool. BPA calculates the annual Slice True-Up  
 17 Adjustment for each fiscal year as soon as BPA's audited actual financial data are available.

18

1 Section 8 discusses Average System Costs (ASCs). The Residential Exchange Program  
2 (REP), established by Section 5(c) of the Northwest Power Act, was designed to provide  
3 residential and farm customers of Pacific Northwest utilities a form of access to low-cost  
4 federal power. 16 U.S.C. § 839c(c). Under the REP, BPA purchases power from each  
5 participating utility at that utility’s average system cost (ASC). ASCs—stated in dollars per  
6 megawatthour (\$/MWh) or mills per kilowatthour (mills/kWh)—are determined by BPA  
7 in separate processes occurring outside the BP-26 rate proceeding for each utility  
8 participating in the REP.

9

10 Section 9 discusses BPA’s revenue forecast. The revenue forecast calculates the expected  
11 revenue from power rates and other sources for the rate period, FY 2026-2028, and the  
12 current year, FY 2025. BPA prepares two revenue forecasts, one using rates from the rate  
13 schedules currently in effect (BP-24 rates) and the second using BP-26 rates. The revenue  
14 forecasts are used to test whether current rates and revised rates will recover the power  
15 revenue requirement.

## 2. RATEMAKING COST OF SERVICE AND RATE DIRECTIVES STEPS

### 2.1 Cost of Service Analysis

#### 2.1.1 Statutory Background

Northwest Power Act Sections 7(b), 7(d), 7(f), and 7(g) direct how BPA allocates resource and other costs to load (rate) pools. 16 U.S.C. §§ 839e(b), 839e(d), 839e(f), 839e(g). This allocation is performed in the Rate Analysis Model for the BP-26 rate period (RAM2026).

Section 7(b)(1) states:

The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under Section 5(c) of this title. Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under Section 5(c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1). Section 7(b)(1) thus describes how BPA is to allocate resource costs to meet the general requirements of public body, cooperative, and federal agency customers within the Pacific Northwest and the loads of electric utilities participating in the REP under § 5(c), collectively called the Priority Firm Power (PF) customer class. *Id.* At this initial stage of the ratemaking process, the PF rate pool consists of the loads of public bodies and cooperatives (collectively identified as preference customers in Northwest Power Act Section 5(b)), federal agency loads, and the loads of REP-participating utilities.

Section 7(b)(1) requires that Federal Base System (FBS) resources be used to serve the PF rate pool until the FBS resources are exhausted. *Id.* Thus, a corresponding amount of

1 FBS costs is allocated to the PF rate pool. After FBS resources are fully used, resources  
2 acquired pursuant to the REP (called exchange resources) are used, and then, if needed,  
3 new resources are used to serve remaining PF rate load. By allocating resource costs in  
4 this order, the appropriate amounts of exchange and new resource costs are allocated to  
5 the PF rate pool.

6  
7 Section 7(d)(1) states:

8 In order to avoid adverse impacts on retail rates of the Administrator's  
9 customers with low system densities, the Administrator shall, to the extent  
10 appropriate, apply discounts to the rate or rates for such customers.

11 *Id.* § 839e(d)(1). Section 7(d)(1) thus authorizes BPA to apply a Low Density Discount  
12 (LDD) to mitigate the costs of customers with relatively fewer retail consumers spread over  
13 relatively larger geographic areas. The LDD is discussed in Sections 2.1.4.3 and 5.4.1  
14 below.

15  
16 Section 7(f) states:

17 Rates for all other firm power sold by the Administrator for use in the Pacific  
18 Northwest shall be based upon the cost of the portions of Federal base system  
19 resources, purchases of power under Section 5(c) of this title and additional  
20 resources which, in the determination of the Administrator, are applicable to  
21 such sales.

22 *Id.* § 839e(f). Section 7(f) prescribes how costs are allocated to rates for all other firm  
23 power after costs are allocated to the PF rate pool and the rates for BPA's direct-service  
24 industrial customers (DSIs) are determined. *Id.* Section 7(f) allocates the remaining  
25 exchange and new resource costs to the remaining regional load (power sold at the New  
26 Resource Firm Power (NR) rate and the Firm Power and Surplus Products and Services  
27 (FPS) rate). *Id.*

1 Section 7(g) states:

2 Except to the extent that the allocation of costs and benefits is governed by  
3 provisions of law in effect on December 5, 1980, or by other provisions of this  
4 section, the Administrator shall equitably allocate to power rates, in  
5 accordance with generally accepted ratemaking principles and the provisions  
6 of this chapter, all costs and benefits not otherwise allocated under this  
7 section, including, but not limited to, conservation, fish and wildlife measures,  
8 uncontrollable events, reserves, the excess costs of experimental resources  
9 acquired under Section 6 of this title, the cost of credits granted pursuant to  
10 Section 6 of this title, operating services, and the sale of or inability to sell  
11 excess electric power.

12 *Id.* § 839e(g). Section 7(g) thus addresses the allocation of costs that are not covered by the  
13 previously cited sections of the Northwest Power Act, such as conservation and fish and  
14 wildlife costs.

15  
16 Consistent with these mandates, the Cost of Service Analysis (COSA) assigns (or “allocates”)  
17 repayment responsibility for BPA’s power revenue requirement (which is grouped into  
18 resource pools, or “cost pools”) to the various classes of service (which are grouped into  
19 load pools, or “rate pools”). These allocations are based upon the resources used to serve  
20 those loads, in compliance with the statutory directives governing BPA’s ratemaking and in  
21 accordance with generally accepted ratemaking principles. The COSA and the other  
22 ratemaking steps are programmed into BPA’s 2026 Rate Analysis Model (RAM2026)  
23 software for purposes of calculating power rates.

### 24 25 **2.1.2 COSA Overview**

26 As noted above, the COSA categorizes loads and resources determined in the Loads and  
27 Resources Study, BP-26-FS-BPA-03, into “pools.” The load pools and resource pools are  
28 then used to calculate Energy Allocation Factors (EAFs). The EAFs are calculated based on  
29 the priorities of service from resource pools to rate pools specified in Section 7 of the  
30 Northwest Power Act, and when Section 7 does not provide guidance, they are based on

1 general principles of cost causation. The COSA then categorizes costs, determined in the  
2 Power Revenue Requirement Study, BP-26-FS-BPA-02, and revenue credits, determined in  
3 the Power and Transmission Risk Study, BP-26-FS-BPA-05, as well as Section 2.1.6 below,  
4 into cost pools. The COSA concludes by using the EAFs to apportion these costs and  
5 revenue credits among the rate pools. Sections 2.1.3 through 2.1.7 provide more detail.

### 6 7 **2.1.3 Loads and Resources**

8 The COSA uses disaggregated customer load data from the source data used to produce the  
9 Power Loads and Resources Study, BP-26-FS-BPA-03. *See* Power Rates Study  
10 Documentation, BP-26-FS-BPA-01A, Table 2.1.1. The disaggregated load data are  
11 aggregated into the PF rate pool (consisting of two sub-pools, the PF Public (PFp) rate pool  
12 and the PF Exchange (PFx) rate pool), the Industrial Firm Power (IP) rate pool, the New  
13 Resource Firm Power (NR) rate pool, and the FPS rate pool. *Id.*, Table 2.2.2.1.

14  
15 The COSA also uses the disaggregated resource data from the source data in the Power  
16 Loads and Resources Study. *Id.*, Table 2.1.2. The disaggregated resource data are  
17 aggregated into the resource pools specified by Section 7 of the Northwest Power Act.  
18 16 U.S.C. § 839e. These resource pools are the FBS resource pool, the exchange resource  
19 pool, and the new resource pool. *Id.*, Table 2.2.2.1. The resources in the FBS and new  
20 resource pools are actual or planned resources that are forecast to be able to serve load  
21 during the rate period. The ratemaking process requires that the forecast firm resources  
22 available to serve load equal BPA's firm load obligations under firm generation. Firm  
23 generation conditions assume very low streamflow conditions based on the historical  
24 record along with today's generating facilities and constraints to yield an amount of energy  
25 output. Firm generation is defined as the monthly 10th percentile (P10) generation of the  
26 federal system. *See* Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.3.

1 **2.1.3.1 Load Pools**

2 Load pools are groupings of forecast sales into customer classes for cost allocation  
3 purposes. These load pools are used to create rate pools. The Northwest Power Act  
4 establishes three rate pools based on the loads served at particular rates. The 7(b) rate  
5 pool includes sales to public body and cooperative customers (consumer-owned utilities or  
6 COUs), federal agencies, and utilities participating in the REP. 16 U.S.C. § 839e(b). The  
7 7(c) rate pool includes sales to BPA’s DSI customers under contracts authorized by  
8 Section 5(d) of the Northwest Power Act. *Id.* § 839e(c). The 7(f) rate pool includes three  
9 types of sales: 1) power sold to consumer-owned utilities which is determined to serve  
10 NLSLs; 2) Section 5(b) requirements power sold to the region’s IOUs; and 3) power sold by  
11 BPA pursuant to Section 5(f) of the Northwest Power Act. *Id.* § 839e(f).

12  
13 The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any  
14 resource costs to the IP rate pool; rather, the IP rate is set using a formula pursuant to  
15 Section 7(c). *Id.* § 839e(c). The formula ties the IP rate to the PF rate. However, if DSI  
16 loads were excluded from cost allocations, loads and resources would be out of balance,  
17 leaving an amount of resource costs not allocated to any loads. Therefore, for ratemaking  
18 purposes BPA allocates resource costs to IP loads as it does to all other remaining firm  
19 power sold. The result is that BPA has, for all practical purposes, only two rate pools, the  
20 7(b) rate pool and all other loads. The resource cost allocations to the IP rate pool are  
21 adjusted later in the Rate Directives Step to conform the IP rate to the statute-based  
22 formula.

23  
24 **2.1.3.2 Resource Pools**

25 The three resource pools are FBS resources, exchange resources, and new resources.

1 The FBS resource pool and associated costs are defined in Section 3(10) of the Northwest  
2 Power Act. *Id.* § 839a(10). The FBS consists of the costs of the following resources: 1) the  
3 Federal Columbia River Power System (FCRPS) hydroelectric projects; 2) resources  
4 acquired by the Administrator under long-term contracts in force on the effective date of  
5 the Northwest Power Act; and 3) replacements for reductions in the capability of the  
6 resources listed in 1) and 2). Market purchases of system augmentation, balancing  
7 purchases, and purchases designated for Tier 2 rates are included as costs of FBS  
8 resources. Forecast costs for FBS resources and associated augmentation during the rate  
9 period are included in the FBS resource cost pool.

10  
11 To implement the direction in Northwest Power Act Section 5(c)(1) that BPA is to purchase  
12 resources from each eligible REP participant and sell an equivalent amount of electric  
13 power to each participant, the exchange resources are sized to be equal to the forecast of  
14 the eligible REP exchange load during the rate period. *Id.* § 839c(c)(1). To calculate the  
15 eligible REP exchange load, the COSA determines whether the potential exchanging utilities  
16 have ASCs that are greater than the applicable base Pfx rate for the rate period. Utilities  
17 with ASCs higher than the base Pfx rate are assumed to participate in the REP during the  
18 rate period. In this way, BPA estimates the Pfx load, the size of the exchange resource pool,  
19 and the costs of the exchange resources (the ASCs multiplied by the eligible exchange  
20 loads). *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.1.3. This  
21 process is iterative and dependent upon the outcomes of the Rate Directives Step.  
22 *See* Section 2.2.2 below.

23  
24 Exchange resources are set equal to the amount of resulting qualifying exchange load,  
25 which implements the direction in Section 5(c)(1) that BPA is to purchase power from each

1 eligible REP participant and sell an equivalent amount of electric power to each participant.  
2 16 U.S.C. § 839c(c)(1).

3  
4 The new resources pool includes all other resources acquired by BPA unless a resource has  
5 been determined to be a replacement for reduced FBS capability.

### 6 7 **2.1.3.3 Order of Resource Service to Load Pools**

8 Section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated  
9 to the PF customer class. *Id.* § 839e(b)(1). FBS resources are used to serve the PF rate pool  
10 until FBS resources are exhausted, whereupon exchange resources and then new resources  
11 are used and, if required, system augmentation in the form of uncommitted market  
12 purchases is forecast to serve any remaining PF loads. After PF loads are met, all remaining  
13 resources are used to serve non-PF loads and, if required, Other Augmentation is forecast  
14 to serve any remaining non-PF loads. Other Augmentation occurs when BPA's total annual  
15 firm energy resources, including any system augmentation to meet PF loads, is less than  
16 BPA's total load obligations including non-PF loads. Section 7(f) of the Northwest Power  
17 Act specifies what and how costs are allocated to "all other firm power" after costs are  
18 allocated to the PF rate pool: the remaining exchange and new resources costs are allocated  
19 to remaining load. *Id.* § 839e(f). That remaining load is served under IP, NR, and FPS  
20 contracts.

21  
22 For the BP-26 rates, the PF load (which includes both PFp and PFx loads) exceeds the  
23 capability of the FBS resources. Therefore, all FBS costs and benefits are allocated to the  
24 PF rate pool. All Exchange Resources are needed to serve PF load; therefore, all costs are  
25 allocated to the PF rate pool. PF loads are served by over half of the new resources, which  
26 includes Other Augmentation. The costs of new resources are allocated proportionally to

1 the firm PF, IP and NR loads it serves. There is no FPS load forecast for BP-26. *See* Power  
2 Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.5.4.

#### 3 4 **2.1.3.4 Load and Resource Adjustments**

5 The Power Loads and Resources Study includes a forecast of the generating capability of all  
6 resources available to BPA to serve its load obligations. Ratemaking uses only the amount  
7 of resources available to serve the rate pool loads; thus, some adjustments must be made.  
8 BPA has certain system obligations, including the Canadian Entitlement and U.S. Bureau of  
9 Reclamation (Reclamation) pumping loads (together called FBS obligations), that have  
10 existed since before the passage of the Northwest Power Act. *See* Treaty between Canada  
11 and the United States of America relating to the Cooperative Development of the Water  
12 Resources of the Columbia River Basin (Columbia River Treaty), Art. VI 4(b), Jan. 17, 1961,  
13 15 U.S.T. 1555, 542 U.N.T.S. 244. FBS resources used to serve these system obligations are  
14 taken “off the top,” removing both the obligation and a corresponding amount of FBS  
15 resource before the ratemaking load-resource balance is calculated.

16  
17 The ratemaking load-resource balance after adjustments is shown in Power Rates Study  
18 Documentation, BP-26-FS-BPA-01A, Tables 2.2.2.1-2.

#### 19 20 **2.1.3.5 Energy Allocation Factors**

21 The aggregated load and resource data are used to calculate the Energy Allocation Factors  
22 (EAFs) that the COSA uses to apportion costs among rate pools. EAFs are calculated for  
23 each resource and rate pool combination by dividing the amount of annual energy load in  
24 each rate pool by the amount served from each resource pool. The annual EAFs for each  
25 resource cost pool and for the rate directive steps are shown in Documentation  
26 Tables 2.2.3.1-2. *Id.* The General and Conservation allocation factors assume a pro rata

1 allocation of costs to all firm loads. For example, the General and Conservation EAFs are  
2 used to allocate some Section 7(g) costs and rate directive allocation adjustments to all firm  
3 energy loads.

#### 4 **2.1.4 Ratemaking Costs**

6 The COSA aggregates costs from the Power Revenue Requirement Study, *id.*,  
7 Tables 2.3.1.1-5, into BPA's ratemaking cost pools specified by Section 7 of the Northwest  
8 Power Act, *id.*, Table 2.3.2.

10 Functionalization of costs between the generation and transmission functions (BPA does  
11 not have a distribution function normal to most utilities) is reflected in the Power Revenue  
12 Requirement Study, BP-26-FS-BPA-02, and the Transmission Revenue Requirement Study,  
13 BP-26-FS-BPA-06. The costs functionalized to the generation function are included in the  
14 power revenue requirement found in the COSA. An exception is exchange resource costs.  
15 *See* Section 2.1.4.2 below. The exchange resource costs are calculated internal to the Rate  
16 Analysis Model (RAM2026). The exchange resource costs include transmission function  
17 costs. The exchange resource costs are functionalized in the COSA modeling so that only  
18 the generation portion of the exchange resource costs is subject to the power cost rate  
19 steps, and the transmission cost portion is then added back in after the Rate Directives Step  
20 is completed. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.2.  
21 In this way, the statutorily mandated power cost relationships between the various rate  
22 pools are maintained without being affected by the transmission function costs of the  
23 exchange.

25 The COSA modeling uses other costs that are internally generated by RAM2026. These  
26 include exchange resource costs, some power purchase costs, revenue shortfall costs

1 associated with some rate credits, and revenues from secondary power sales. These are  
2 covered in greater detail below.

#### 3 4 **2.1.4.1 Revenue Requirement**

5 The revenue requirement from the Power Revenue Requirement Study is supplemented in  
6 the COSA for costs that are determined in other steps of the ratemaking process (such as  
7 projected balancing purchase power costs; system augmentation costs; PNRR, if any; and  
8 the functionalized exchange resource costs). Disaggregated costs are listed in a form  
9 consistent with the income statement from the Power Revenue Requirement Study and are  
10 shown in Table 2.3.1.1-5. *Id.* RAM2026 uses unique identifier key codes to categorize these  
11 costs to the COSA cost pools. *Id.*, Table 2.3.2.

12  
13 In addition to costs associated with operation of the FCRPS, there are three categories of  
14 purchased power that are included in the COSA: 1) purchased power under contract;  
15 2) forecast system augmentation; and 3) forecast balancing power purchases.

- 16  
17 1. **Purchased Power.** The purchased power subset of purchased power costs  
18 includes the costs of acquisition of power through renewable energy, wind,  
19 geothermal, and competitive acquisition programs. Costs of purchased power  
20 from the Power Revenue Requirement Study are included in the new resources  
21 pool.
- 22 2. **System Augmentation.** For ratemaking purposes, it may be assumed that  
23 BPA acquires resources beyond the inventory represented by the system  
24 generating resources and balancing power purchases if loads exceed resources  
25 under firm generation assumptions. System augmentation amounts are  
26 determined in the Power Loads and Resources Study and are used to meet

1 annual customer firm power loads in excess of annual firm system resources.  
2 System augmentation includes any Tier 1 system augmentation required to  
3 meet any annual deficits of the federal system for Tier 1 load service and Tier 2  
4 augmentation to meet Tier 2 load service that is greater than the forecasted  
5 available federal system. *See* Power Loads and Resources Study, BP-26-FS-  
6 BPA-03, § 4.2. Typically, system augmentation is reflected as an uncommitted  
7 market purchase and the cost is based on the remarketing value. *See* Section  
8 3.2.6 below. System augmentation purchases are treated as FBS costs and, as  
9 such, the costs are included in and allocated as FBS costs. *See* Power Rates  
10 Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

- 11 3. **Balancing Power Purchases.** The costs of power purchases and storage  
12 required to meet firm deficits on a monthly/diurnal basis are included in the  
13 category of balancing power purchases. Projected balancing power purchases  
14 are generally needed to serve firm loads in months other than the spring fish  
15 migration period under some water conditions. Balancing purchase expenses  
16 are calculated for each monthly/diurnal period where BPA is energy deficit  
17 across all 2,700 iterations in the Revenue Simulation Model (RevSim). The  
18 median purchasing price and quantity associated with these purchases for  
19 each year of the rate period are passed to RAM2026 to compute balancing  
20 purchase costs. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05,  
21 § 3.1.2.1. Balancing power purchases are treated as FBS costs and, as such, the  
22 costs are included in and allocated as FBS costs. *See* Power Rates Study  
23 Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

24  
25 Other Augmentation also plays a role. Other Augmentation is forecast to occur when  
26 BPA's annual firm energy resources including system augmentation are less than

1 BPA's total load obligations. Typically, Other Augmentation is necessary to serve non-  
2 PF loads under IP, NR, and FPS contracts. Other Augmentation amounts are  
3 determined in the Power Loads and Resources Study. *See* Power Loads and Resources  
4 Study, BP-26-FS-BPA-03, § 4.2. Other Augmentation costs are treated as uncommitted  
5 market purchases priced using the Remarketing Value. *See* Section 3.2.6 below. Other  
6 Augmentation is classified as a new resource and, as such, the costs are included in  
7 the new resource cost pool in the COSA. *See* Power Rates Study Documentation,  
8 BP-26-FS-BPA-01A, Table 2.3.2.

#### 9 10 **2.1.4.2 Functionalization of Exchange Resource Costs**

11 In the COSA, exchange resource costs are based on participating utilities' ASCs and their  
12 exchange power sales to BPA. Each utility's ASC includes the cost of power and  
13 transmission services associated with serving the utility's TRL. By definition, exchange  
14 resource sales to BPA equal the exchange sales by BPA. The rate directive adjustments that  
15 occur subsequent to the COSA use the results of the COSA allocations of the generation  
16 revenue requirement. Therefore, because the exchange resource costs in the COSA include  
17 transmission costs, the PFX rate includes a transmission cost adder, and the exchange  
18 resource costs are functionalized between power and transmission.

19  
20 The exchange resource costs functionalized to power continue through the ratemaking  
21 process. The exchange resource costs functionalized to transmission are removed from the  
22 generation revenue requirement for the Rate Directives Step and are added back to  
23 determine the PFX rate after the Rate Directives Step is completed. In this way, the  
24 exchange resource costs functionalized to power are treated the same as other power  
25 function costs through the rate development process. The transmission function costs are  
26 collected directly from PFX loads through a transmission adder included in the PFX rate.

1 Because the amount of exchange resource costs functionalized to transmission is equal to  
2 the increased revenue due to the PFx rate adder, there is no net cost to other rates due to  
3 these transmission costs. The functionalization of exchange resource costs is shown in  
4 Table 2.3.4.2. *Id.*

#### 6 **2.1.4.3 Low Density Discount**

7 Section 7(d)(1) of the Northwest Power Act instructs BPA to apply a Low Density Discount  
8 (LDD) to mitigate the costs of customers with relatively fewer consumers spread over  
9 relatively larger geographic areas. 16 U.S.C. § 839e(d)(1). *See* Power Rate Schedules and  
10 General Rate Schedule Provisions (GRSPs), BP-26-A-01-AP01, GRSP II.B.

11  
12 The cost of providing the discount is computed in RAM2026 using offset quantities and the  
13 internally computed TRM rates. Offset quantities are the sum of the applicable LDD  
14 percentages applied to the customer-specific billing determinants. *See* TRM, BP-12-A-03,  
15 § 10.2. These offsets are computed in the TRM Billing Determinants Model (TRMbd), which  
16 is a module of RAM2026.

17  
18 The estimated cost of the LDD is shown in Power Rates Study Documentation, BP-26-FS-  
19 BPA-01A, Table 2.3.3.1. The entire cost of the discount is allocated to the PF load pool prior  
20 to linking the IP rate to the PF rate. *Id.*, Table 2.3.4.1.1

#### 22 **2.1.4.4 Irrigation Rate Discount**

23 A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and  
24 the TRM. The discount is a rate, expressed in mills per kilowatthour that, when applied to  
25 qualified irrigation load, produces a dollar credit on eligible customers' power bills. *See*  
26 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.C. The Irrigation Rate

1 Discount (IRD) rate is calculated in RAM2026, as described in Section 5.4.2 below. The cost  
2 of the discount is computed in RAM2026 using contract irrigation loads and the internally  
3 calculated rate. The entire cost of the IRD is allocated to the PF load pool prior to linking  
4 the IP rate to the PF rate.

### 6 **2.1.5 Cost Pools**

7 The COSA has six cost pools for the initial allocation of BPA's power costs: FBS resource  
8 costs, exchange resource costs, new resource costs, conservation costs, BPA program costs,  
9 and power transmission costs. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A,  
10 Table 2.3.2. These costs are allocated to the rate pools using direction from  
11 Sections 7(b)(1), 7(d), 7(f), and 7(g) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(1),  
12 839e(f), 839e(g).

#### 14 **2.1.5.1 Section 7(b)(1) and 7(d) Costs**

15 Section 7(b)(1) costs are associated with the resource cost pools necessary to serve  
16 PF load, including the PFp load and the PFX load. 16 U.S.C. § 839e(b)(1). For the BP-26  
17 rates, these resources include all of the FBS resources and all of the exchange resources.  
18 Therefore, all FBS resource costs and all exchange resource costs are Section 7(b)(1) costs  
19 allocated to serve Section 7(b)(1) loads. Costs associated with the LDD under Section 7(d)  
20 and the IRD are allocated along with Section 7(b)(1) costs.

#### 22 **2.1.5.2 Section 7(f) Costs**

23 Section 7(f) costs are generally associated with the resource cost pools necessary to serve  
24 non-PF load, including IP, NR, and FPS loads. *Id.* § 839e(f). For the BP-26 rates, these  
25 resources include the new resources which contains Other Augmentation. Therefore, most

1 new resource costs are Section 7(f) costs allocated to serve all remaining loads; that is, IP,  
2 NR, and FPS loads.

### 3 4 **2.1.5.3 Section 7(g) Costs**

5 **Conservation Costs.** The Northwest Power Act requires BPA to treat cost-effective  
6 conservation savings as a resource in planning to meet the Administrator’s obligations to  
7 serve loads. The “conservation” line item, as seen in Power Rates Study Documentation,  
8 BP-26-FS-BPA-01A, Tables 2.3.1.1-5, includes 1) amortization of BPA’s previous  
9 conservation resource acquisition activities; 2) BPA’s continuing contributions to the  
10 region’s market transformation efforts; 3) costs associated with BPA’s energy efficiency  
11 business; and 4) a share of Net Revenues (Minimum Required Net Revenues (MRNR) plus  
12 PNRR, if any). Conservation costs are allocated to all rate pools using the Conservation &  
13 General EAF. *Id.*, Table 2.3.4.3.

14  
15 **BPA Program Costs.** Some of BPA’s program costs are not identified directly with any  
16 specific resource pool. An example is the cost of tracking and implementing national  
17 energy policies and initiatives. Development of these power program costs occurs in the  
18 Integrated Program Review (IPR), as described in Power Revenue Requirement Study,  
19 BP-26-FS-BPA-02, Section 2.1. The power portion appears in the COSA as BPA program  
20 costs. BPA program costs are allocated to all rate pools using the Conservation & General  
21 EAF. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.3.

22  
23 **BPA Power Transmission Costs.** Power transmission expenses include the costs of  
24 serving customers under Transfer Service. *See* Section 6 below. They also include the costs  
25 Power Services incurs to procure transmission and ancillary services to transmit surplus  
26 federal power to purchasers that do not hold transmission contracts, primarily outside the

1 Pacific Northwest. BPA also has federal generation that exists in third-party service  
2 territories; both wheeling costs and financial payments to cover losses are included in this  
3 category of costs. Finally, it includes an FCRPS generation-integration cost. Transmission  
4 costs are allocated to all rate pools based on the Conservation & General EAF except third  
5 Party General Transfer Agreement (GTA) wheeling costs (also referred to as Transfer  
6 Costs) are allocated between the PF and NR rate pools based on usage. Under the BP-26  
7 settlement terms NR GTA wheeling costs are forecast to be zero. Administrator's Final  
8 Record of Decision, BP-26-A-01, Appendix A § IV.G. In addition, the Transmission and  
9 Ancillary Services (Non-Slice) costs supporting non-system obligations uses the FBS EAF.  
10 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.3.

11

#### 12 **2.1.5.4 Planned Net Revenues for Risk**

13 PNRR is an amount of net revenues required to be recovered from power rates to ensure  
14 that cash flows from such rates are sufficient to meet BPA's TPP Standard. *See* Power and  
15 Transmission Risk Study, BP-26-FS-BPA-05, § 2.3. PNRR may also include an amount of  
16 additional revenue to build financial reserves under the FRP. Power and Transmission  
17 Risk Study, BP-26-FS-BPA-05, Appendix A (FRP), § 4.2.

18

19 Under the ratemaking methodology, the amount of PNRR (if any) needed to meet the TPP  
20 Standard is the result of an iterative process among several models: RAM2026, RevSim, and  
21 ToolKit. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4. The iteration is  
22 initiated with a seed value of \$0 for PNRR in the Power Rates Study Documentation, BP-26-  
23 FS-BPA-01A, Tables 2.3.1.4 and 2.3.2. The resulting rates are used in RevSim to produce  
24 net revenue probability distributions. These net revenue distributions are then used in the  
25 ToolKit to test whether TPP is at least 92.6 percent over the three-year rate period. If not,  
26 the ToolKit produces a new PNRR value that just meets the TPP standard, rates are

1 recalculated, a new distribution of net revenues is created, and TPP is calculated for the  
2 new distribution. The iterations are stopped when the smallest value of PNRR that meets  
3 the TPP standard has been determined. *Id.*, Table 2.3.1.4. Because no PNRR was required  
4 to meet the TPP Standard in the BP-26 rates, no iterative process was necessary. No PNRR  
5 was required in the BP-26 rates for liquidity purposes because any accrual of additional  
6 cash reserves required by the FRP is to be collected through the FRP Surcharge. *See*  
7 Section 5.2.2 below.

#### 9 **2.1.5.5 New Expenses**

10 BPA will allocate new expenses to the six cost pools using direction from Sections 7(b)(1),  
11 7(f), and 7(g) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(1), 839e(f), 839e(g).  
12 For BP-26, four new costs were added to RAM2026. The new costs have been identified  
13 below including the cost pool it is being allocated too.

- 14 1. Amortization of P2IP Settlement Payments, a FBS resource costs.
- 15 2. Long Term Funding Agreements (Accords), a FBS resource costs.
- 16 3. Payments for Litigation of Stay Agreements (P2IP), a FBS resource costs.
- 17 4. Other Augmentation, a new resource cost.

18 Consistent with the Update to BPA’s BP-26 Cost Projections, issued on July 14, 2025, cost  
19 projections in power rates associated with the Memorandum of Understanding filed on  
20 December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v.*  
21 *National Marine Fisheries Service*, No. 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were  
22 removed. Email from Bonneville Power Administration to Tech Forum Subscribers, Update  
23 to BPA’s BP-26 Cost Projections (July 14, 8:11 PST) (on file with author) (“Update to BPA’s  
24 BP-26 Cost Projections”); *see* Power Rates Study Documentation, BP-26-FS-BPA-01A,  
25 Tables 2.3.1.1-5.

1 **2.1.6 Revenue Credits**

2 In addition to allocating cost data, the COSA allocates various revenue credits that offset  
3 costs in each rate pool. Allocation of revenue credits follows the same principles as the  
4 allocation of costs, based upon statutory guidance. For example, some revenue credits are  
5 associated with the operation of FBS resources and reduce FBS resource costs to be  
6 recovered by PF rates. Some revenue credits reduce the new resource and conservation  
7 costs. Other revenue credits that are not associated with any particular cost pool are  
8 allocated to rate pools pro rata to load using the Conservation & General EAF. *Id.*,  
9 Table 2.2.3.2.

10  
11 **2.1.6.1 Downstream Benefits and Pumping Power Revenues**

12 Downstream benefits and pumping power revenues are described in Section 9.2 below.  
13 Downstream benefits and pumping power revenues are associated with FBS resources, and  
14 these credits are allocated to the same loads to which FBS costs are allocated. *See id.*,  
15 Table 2.3.6.

16  
17 **2.1.6.2 Section 4(h)(10)(C) Credits**

18 Section 4(h)(10)(C) credits are described in Section 9.4.1. The forecast credit is calculated  
19 as described in the Power and Transmission Risk Study, Section 4.1, and supplied to  
20 RAM2026. Section 4(h)(10)(C) credits are associated with FBS resources, and the credits  
21 are allocated to the same loads to which FBS costs are allocated. *Id.*

22  
23 **2.1.6.3 FBS Contract Obligations Revenue**

24 BPA has certain FBS obligations that provide revenues. For the BP-26 period, this  
25 includes only Upper Baker revenues for energy and capacity purchased by Puget  
26 Sound Energy to enable flood control elevation levels at that project. These FBS

1 system obligation revenues are allocated to the same loads to which FBS costs are  
2 allocated. *See id.*

#### 3 4 **2.1.6.4 Colville Credit**

5 The Colville credit is described in Section 9.4.2 below. The Colville credit is associated with  
6 FBS resources, and this credit is allocated to the same loads to which FBS costs are  
7 allocated. *Id.*

#### 8 9 **2.1.6.5 Miscellaneous Revenues**

10 Miscellaneous revenues are described in Section 9.2 below. These revenues are allocated  
11 to all firm loads through the Conservation & General EAF. *Id.*, Table 2.2.3.1.

#### 12 13 **2.1.6.6 Renewable Energy Certificates**

14 Revenues result from BPA's sales of Renewable Energy Certificates (RECs). For  
15 FY 2026-2028, no revenues are expected, and the forecast is zero. *Id.*

#### 16 17 **2.1.6.7 General Revenue Credits**

18 In the course of marketing power, Power Services generates transmission-related revenues  
19 and credits. The revenues and credits are predominantly revenues associated with  
20 providing reserves and energy for ancillary services, control area services, and other  
21 reliability needs. *See* Section 9.3 below. In addition to revenues associated with generation  
22 inputs, FPS Real Power Losses, NR Energy Shaping Service (NR ESS) products for NLSL  
23 service, and Resource Support Services for non-federal resources are allocated using the  
24 FBS EAF. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.7.5  
25 and 2.3.7.6.

1 **2.1.6.7.1 Tiered Rates Adjustment Credit**

2 The Tiered Rates Adjustment revenue credit reflects the value associated with selling  
3 energy from the federal system to serve Tier 2 loads within the 7(b) rate pool. The Tiered  
4 Rates Adjustment is categorized as a FBS revenue credit and assigned to the Composite  
5 cost pool. *See id.*, Table 2.3.7.1.

6  
7 The Tiered Rates Adjustment credit is calculated internally within RAM2026 by taking the  
8 annual average megawatts (aMW) of the federal system serving Tier 2 loads for a specific  
9 year of the rate period, multiplying it by the respective annual hours and reported  
10 remarketing value. *See* Section 3.2.6 below.

11  
12 **2.1.6.8 Secondary Energy Revenue Credits**

13 The Secondary Energy Revenue Credit adjustment recognizes that BPA collects revenues  
14 from certain power sales to which costs are not allocated. BPA credits these revenues to  
15 classes of service served with firm federal power.

16  
17 The ratemaking process ensures that the forecast of firm resources available to serve load  
18 is equal to BPA's firm load obligations under firm generation conditions. However, if firm  
19 load obligations exceed firm resources, a system augmentation purchase is assumed to  
20 achieve load-resource balance. If firm resources exceed firm load obligations, a firm  
21 surplus secondary sale is assumed to achieve load-resource balance. System Augmentation  
22 expenses are included as FBS costs in the COSA. *See* Section 2.1.4.1 above. Firm Surplus  
23 Secondary Sales are included in the secondary revenue credit calculation but allocated in  
24 the Surplus Power Sales Revenue Deficiency/Surplus Reallocation. *See* Section 2.1.7 below.

25  
26 Non-firm secondary sales recognize that better than firm generation conditions will most  
27 likely occur. Generation from water in excess of firm conditions is called secondary energy.

1 The projected secondary energy revenue credits are included so that power rates are set at  
2 a level such that revenues from all sources do not recover more than the total Power  
3 Services revenue requirement.

4  
5 The sales of secondary energy in excess of firm obligations on a monthly/diurnal basis  
6 under 2,700 iterations of different risk conditions are calculated by RevSim. Power and  
7 Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1; *see also* Power Rates Study  
8 Documentation, BP-26-FS-BPA-01A, Table 2.3.8. Mean prices and quantities of these  
9 secondary sales, as well as mean market prices, are passed to RAM2026 for the purposes of  
10 the secondary revenue credit and the computation of the load shaping rates.

11  
12 The quantity of secondary sales is valued at expected wholesale market prices in the  
13 Northwest at the Mid-Columbia (Mid-C) trading hub. However, BPA makes transactions  
14 outside the Northwest. The incremental value of extra-regional sales is computed in  
15 RevSim and passed to RAM2026 as an aggregate dollar value to be included in the  
16 secondary revenue credit after accounting for both transmission availability and regional  
17 price differences. Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3; *see*  
18 *also* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.8.

19  
20 For the BP-26 rate period, the value associated with market participation in the Energy  
21 Imbalance Market (EIM) is estimated by simulating EIM dispatch using forecast hourly  
22 Northwest market prices at Mid-C and projected BPA system flexibility gained by no longer  
23 holding Non-Regulating balancing reserves. This value is directly input into RAM2026.  
24 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.8.

1 Per the BP-26 Settlement Agreement, Administrator’s Final Record of Decision, BP-26-A-  
2 01, Appendix A § IV.C, additional net secondary revenues are included for each year of the  
3 rate period. These values are directly input into RAM2026 and captured within the  
4 “Adjustments to Secondary Sales” line in Table 2.3.8 of the Power Rates Study  
5 Documentation, BP-26-FS-BPA-01A.

6  
7 The secondary revenues projected in RevSim are for market sales BPA expects to make on  
8 behalf of Non-Slice customers. However, RevSim also calculates the value of secondary  
9 energy that is expected to be sold by Slice customers. This value for Slice secondary also  
10 includes an incremental value for extra-regional sales. The ratemaking process does not  
11 consider product choice by preference customers until the Rate Design Step; therefore, the  
12 revenues from RevSim used at this stage of ratemaking include all secondary energy  
13 expected to be produced by federal generation. *Id.*, Table 2.3.8. Secondary energy  
14 revenues are allocated to rate pools based on the FBS EAF to credit the revenues against  
15 the costs of the resources producing the secondary energy.

### 16 17 **2.1.7 Surplus Power Sales Revenue Deficiency/Surplus Reallocation**

18 BPA sells surplus firm power under the FPS rate schedule. If BPA anticipates firm  
19 generation to exceed firm load obligations on an annual average basis, Firm Surplus  
20 Secondary Sales are included as a revenue credit. The COSA includes the quantity of these  
21 sales in the FPS rate pool and allocates costs to these sales. Sales of such firm power are  
22 not necessarily made at rates that recover the exact costs allocated in the COSA to these  
23 sales. Therefore, either a revenue surplus or a revenue deficiency will result when the  
24 costs allocated to the sales of this firm power are compared with the revenues received  
25 under the applicable contract. The expected revenue forecast from the sale of firm power  
26 and settlements, the allocated costs, and the resulting FPS revenue deficiency are shown in

1 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.9. This revenue  
2 deficiency is allocated to all other firm power (PF, IP, and NR) rates.

3  
4 This is the final step of the COSA. At this point, all of BPA's costs have been allocated to the  
5 PF, IP, NR, and FPS rate pools, as have all revenues derived from sources other than these  
6 rate pools. After completion of the COSA, certain statutory reallocations of these COSA-  
7 allocated costs are performed in the Rate Directives Step.

## 8 9 **2.2 Rate Directives Step**

### 10 **2.2.1 Statutory Background**

11 Northwest Power Act Sections 7(c), 7(b)(2), and 7(b)(3) provide guidance for the Rate  
12 Directives Step. 16 U.S.C. §§ 839e(c), 839e(b)(2), 839e(b)(3). After the COSA allocation of  
13 costs and credits to rate pools, the Rate Directives Step reallocates costs among rate pools  
14 to ensure that the relationships between the rates for the different classes of customers  
15 comport with the rate directives in the Northwest Power Act.

16  
17 Section 7(c), in pertinent part, states:

18       The rate or rates applicable to direct service industrial customers shall be  
19       established for the period beginning July 1, 1985, at a level which the  
20       Administrator determines to be equitable in relation to the retail rates  
21       charged by the public body and cooperative customers to their industrial  
22       consumers in the region.

23 16 U.S.C. § 839e(c). Section 7(c) describes how BPA is to set the rate it charges DSI  
24 customers. *Id.* It provides that the DSI rate will be set to be equitable in relation to retail  
25 industrial rates of consumer-owned utility (COU) customers. Section 7(c) provides  
26 guidance on how to establish and modify this equitable relationship:

27       The [DSI rate] shall be based upon the Administrator's applicable wholesale  
28       rates to such public body and cooperative customers and the typical margins

1 included by such public body and cooperative customers in their retail  
2 industrial rates but shall take into account the comparative size and character  
3 of the loads served, the relative costs of electric capacity, energy, transmission,  
4 and related delivery facilities provided and other service provisions, and  
5 direct and indirect overhead costs, all as related to the delivery of power to  
6 industrial customers, except that the Administrator's rates during such period  
7 shall in no event be less than the rates in effect for the contract year ending on  
8 June 30, 1985.

9 *Id.* Section 7(c) speaks of the "applicable wholesale rates" to COUs plus the "typical  
10 margins" included by those customers in their retail industrial rates. *Id.* The computation  
11 of these elements of the DSI rate is discussed below in Section 2.2.2.5.1-2, Section 4.3.1.1.2,  
12 and Appendix A. Section 7(c) also requires a comparison of the DSI rate to the DSI rate in  
13 effect in 1985, as discussed in Section 2.2.2.5.4 below. *Id.*

14  
15 Finally, Section 7(c)(3) provides:

16 The Administrator shall adjust such rates to take into account the value of  
17 power system reserves made available to the Administrator through his rights  
18 to interrupt or curtail service to such direct service industrial customers.

19 *Id.* § 839e(c)(3). Section 7(c)(3) thus directs that the DSI rate is to be adjusted to account  
20 for the value of power system reserves provided through contractual rights that allow BPA  
21 to restrict portions of the DSI load. This adjustment is typically made through a Value of  
22 Reserves (VOR) Credit. The VOR analysis is discussed in Sections 2.2.2.5.2 and 4.3.1.1.1  
23 below.

24  
25 In summary, the result of Section 7(c) requirements is that the DSI rate is set equal to the  
26 applicable wholesale rate, plus the typical margin, minus the VOR Credit, subject to the DSI  
27 floor rate test. Because the DSI rate interacts with the PF rate and the NR rate, the three  
28 rates are determined simultaneously through a solution called the 7(c)(2) delta. The  
29 determination and application of the 7(c)(2) delta are discussed below in Sections 2.2.2.1-4  
30 and 2.2.2.5.1-4 and applied to the IP rate in Section 4.3.1.1.

1 Section 7(b)(2) states:

2 After July 1, 1985, the projected amounts to be charged for firm power for the  
3 combined general requirements of public body, cooperative and Federal  
4 agency customers, exclusive of amounts charged such customers under  
5 subsection (g) of this section for the costs of conservation, resource and  
6 conservation credits, experimental resources and uncontrollable events, may  
7 not exceed in total, as determined by the Administrator, during any year after  
8 July 1, 1985, plus the ensuing four years, an amount equal to the power costs  
9 for general requirements of such customers if the Administrator assumes [five  
10 specified assumptions].

11 *Id.* § 839e(b)(2). Section 7(b)(2) describes a rate test designed to ensure that preference  
12 customers' firm power rates are no higher than rates calculated using five assumptions that  
13 remove specified effects of the Northwest Power Act. *Id.* The rate test is now implemented  
14 through provisions of the 2012 Residential Exchange Program Settlement Agreement,  
15 which resolved challenges to BPA's previous implementation of Sections 7(b)(2) and  
16 7(b)(3). *See* 2012 Residential Exchange Program Settlement Agreement, Contract No.  
17 11PB-12322, REP-12-A-02A (2012 REP Settlement). The 2012 REP Settlement provides  
18 the manner by which BPA computes the amount of rate protection for preference  
19 customers, and the amount of REP benefits to the IOUs, in lieu of performing the rate test  
20 every rate period.

21  
22 Section 7(b)(3), in pertinent part, states:

23 Any amounts not charged to public body, cooperative, and Federal agency  
24 customers by reason of [section 7(b)(2)] shall be recovered through  
25 supplemental rate charges for all other power sold by the Administrator to all  
26 customers.

27 16 U.S.C. § 839e(b)(3). Section 7(b)(3) directs that the cost of any rate protection afforded  
28 to preference customers arising from implementation of Section 7(b)(2) be borne by all  
29 other BPA power sales. *Id.* The rate protection does not extend to all PF customers: the  
30 public body, cooperative, and federal agency customers receive the rate protection, but  
31 REP participants do not. Thus, to allow the cost reallocations due to the rate protection, the

1 PF rate is bifurcated. The two resulting rates are the PF Public (PFp) rate, which receives  
2 the rate protection, and the PFx rate, which does not receive rate protection and bears its  
3 allocated share of the rate protection reallocation. The rate protection amount is collected  
4 through additional charges included in rates for all non-PF Public sales. The reallocation of  
5 rate protection costs is discussed in Section 2.2.2.3 below. The 2012 REP Settlement  
6 retains the allocation of rate protection costs to all other rates through mechanisms  
7 specified therein. *See* 2012 REP Settlement, REP-12-A-02A.

## 9 **2.2.2 Rate Directives Step Modeling**

10 The Rate Directives Step modeling takes as input the costs allocated to the four rate pools  
11 (PF, IP, NR, and FPS) from the COSA modeling. The Rate Directives Step adjusts these  
12 initial allocations among the PF, IP, and NR rate pools with reallocations of costs that  
13 conform to Section 7 of the Northwest Power Act. 16 U.S.C. § 839e. At this point in the  
14 modeling, the allocation of costs to the FPS rate pool is equal to the expected revenues from  
15 FPS sales and will not be altered throughout the remaining ratemaking steps.

### 17 **2.2.2.1 First IP-PF Rate Link**

18 The IP rate for sales of power to BPA's DSI customers is a formula rate tied to the  
19 unbifurcated PF rate (*i.e.*, the PF rate at this point in the modeling includes costs to be  
20 allocated between the PFp and PFx rate sub-pools later in the process). Also, at this point  
21 in the modeling, the costs allocated to the IP and NR rate pools are equal on a per-  
22 megawatt-hour basis. An adjustment is needed to set the IP rate to its proper relationship  
23 with the PF rate. That adjustment, the IP-PF Link 7(c)(2) rate adjustment, will result in the  
24 7(c)(2) delta, thereby reducing the allocated costs to the IP rate pool and increasing the  
25 costs allocated to the PF and NR rate pools.

1 The IP-PF Link adjustment sets the IP rate equal to the monthly/diurnal PFp energy rates  
2 applied to DSI Billing Determinants, plus the net industrial margin. To determine the  
3 IP rate, the model first calculates the net industrial margin by subtracting the VOR provided  
4 by sales to the DSIs from the typical industrial margin calculated in the 7(c)(2) Margin  
5 Study, Power Rates Study, BP-26-FS-BPA-01, Appendix A. See Power Rates Study  
6 Documentation, BP-26-FS-BPA-01A, Table 2.4.1. Monthly and diurnally PF melded rates  
7 are calculated as described in Section 4.1.3 below. *Id.*, Tables 2.4.2 and 2.4.3. Because the  
8 IP-PF Link calculation maintains a set relationship between the levels of the IP and PF rates  
9 for each year and simultaneously allocates costs between the two rates, and to avoid  
10 multiple iterations, RAM2026 has an algebraic formula to approximate a solution and then  
11 uses an intrinsic Excel function, "Goal Seek," to converge on a solution for each year of the  
12 rate test period. *Id.*, Table 2.4.4.

13  
14 After allocation of the 7(c)(2) delta in the IP-PF Link reallocation, the IP floor rate test  
15 determines if the currently calculated IP rate is below the IP rate that was in effect for the  
16 contract year ending on June 30, 1985, as required by Section 7(c)(2) of the Northwest  
17 Power Act. 16 U.S.C. § 839e(c)(2). The BP-26 IP rate at this point in the modeling is not  
18 below the IP floor rate, and no floor rate adjustment is needed.

#### 20 **2.2.2.2 Determination of Active Exchanging Utilities**

21 With the proper relationship between the IP rate and the unbifurcated PF rate established,  
22 the base PFx rates for the IOUs and the COUs can be calculated. The base PFx rate for the  
23 IOUs is the average unbifurcated PF rate plus a transmission adder. The base PFx rate for  
24 the COUs begins with the IOU rate and removes Tier 2 costs and loads. A test is again  
25 conducted to determine if the ASCs of the potential IOU and COU exchanging utilities are

1 greater than the IOU and COU base PFx rates. If a utility's ASC is greater than its base PFx  
2 rate, the utility is included as an active exchanging utility.

### 4 **2.2.2.3 7(b)(2) Rate Protection and 7(b)(3) Reallocations**

5 The next step is to calculate the level of rate protection due to preference customers as a  
6 result of the ASC and PFx calculation and pursuant to Section 7(b)(2) of the Northwest  
7 Power Act. 16 U.S.C. § 839e(b)(2). The rate test specified in Section 7(b)(2) of the  
8 Northwest Power Act ensures that BPA's rates for public body, cooperative, and federal  
9 agency customers (collectively referred to as preference customers or 7(b)(2) customers)  
10 are no higher than rates calculated using specific assumptions that remove certain effects  
11 of the Northwest Power Act. *Id.* The BP-26 rates are calculated pursuant to a settlement of  
12 litigation associated with the REP and the Section 7(b)(2) rate test. *See* 2012 REP  
13 Settlement, REP-12-A-02A, at 1. The 2012 REP Settlement was evaluated for compliance  
14 with, among other statutory provisions, Sections 7(b)(2) and 7(b)(3). 16 U.S.C.  
15 § 839e(b)(2)-(3).

16  
17 Rate modeling for the REP under the 2012 REP Settlement begins with total IOU REP  
18 benefits, as specified in the 2012 REP Settlement, known as Scheduled Amounts. *See* Power  
19 Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.9.

20  
21 The 2012 REP Settlement rate modeling first calculates the Unconstrained Benefits, which  
22 are the REP benefits that would be in place if there were no PFp rate protection. In such a  
23 circumstance, the REP benefits for each exchanging utility would be its ASC minus its  
24 appropriate Base PFx rate multiplied by its qualified exchange load. The Unconstrained  
25 Benefits are shown in Table 2.4.10. *Id.* These Unconstrained Benefits are then used to  
26 calculate COU REP benefits, as specified in individual settlements with each eligible COU.

1 COU REP benefits are calculated using a ratio of 1) the IOU Scheduled Amounts to 2) the  
2 total IOU Unconstrained Benefits for IOUs. This ratio is then multiplied by COU  
3 Unconstrained Benefits to derive COU REP benefits.

4  
5 The total rate protection provided to preference customers is composed of two parts. With  
6 the Unconstrained Benefits and the total IOU and COU REP benefits determined, the first  
7 part of rate protection due to preference customers is calculated as the Unconstrained  
8 Benefits minus the sum of REP benefits. The REP Settlement modeling then allocates this  
9 amount to individual REP participants. This allocation to each REP participant is divided  
10 by the exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge  
11 that is added to the appropriate Base Pfx rates to produce a utility-specific Pfx rate.

12 *See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.11.* After the utility-  
13 specific Pfx rates are calculated, the utility-specific REP benefits are calculated and  
14 summed after any reallocations necessary under Section 6.2 of the 2012 REP Settlement  
15 Agreement. *See id.*, Tables 2.4.11 and 2.4.12 (showing reallocations between participating  
16 IOUs pursuant to Section 6.2 of the 2012 REP Settlement Agreement).

17  
18 A second part of rate protection, the REP Surcharge, is calculated and allocated to the IP  
19 and NR rate pools. The REP Surcharge is determined by multiplying the REP benefit costs  
20 determined above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in  
21 the 2012 REP Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the  
22 IP and NR rates and increases this historical 7(b)(3) rate surcharge in direct proportion to  
23 increases in REP Recovery Amounts relative to WP-10 REP benefit levels. The REP  
24 Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules,  
25 produces an amount of rate protection dollars. *Id.*, Table 2.4.14. This amount is allocated  
26 to the IP and NR rate pools.

1 The REP Settlement rate protection allocations increase the IP, NR, and PFx rates while  
2 decreasing the PFp rate. *Id.*, Tables 2.4.13, 2.4.14, and 2.4.15.

#### 3 4 **2.2.2.4 Second IP-PF Rate Link**

5 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must  
6 be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second  
7 IP-PF Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is  
8 set equal to the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. At this  
9 point in the ratemaking process, a reallocation of costs (consistent with Section 2.2.2.5  
10 below) establishes the NR rate. *Id.*, Tables 2.4.16, 2.4.17, 2.4.18, and 2.4.19.

#### 11 12 **2.2.2.5 IP Rate**

13 The IP rate is calculated using directives in Sections 7(c)(1), 7(c)(2), and 7(c)(3) of the  
14 Northwest Power Act. 16 U.S.C. § 839e(c)(1)-(3). As discussed in Section 2.2.1 above,  
15 Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set  
16 “at a level which the Administrator determines to be equitable in relation to the retail rates  
17 charged by the public body and cooperative customers to their industrial consumers in the  
18 region.” *Id.* § 839e(c)(1). “Equitable in relation” pursuant to Section 7(c)(2) is defined as  
19 basing the DSI rate on BPA’s “applicable wholesale rates” to its COU customers plus the  
20 “typical margins” included by those customers in their retail industrial rates. *Id.*  
21 § 839e(c)(2). Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the  
22 value of power system reserves provided through contractual rights that allow BPA to  
23 restrict portions of the DSI load. *Id.* § 839e(c)(3). This adjustment is made through a VOR  
24 Credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate,  
25 plus the typical margin, plus the VOR Credit, subject to the DSI floor rate test and the  
26 outcome of the determination of PFp rate protection.

1 **2.2.2.5.1 Applicable Wholesale Rate**

2 The applicable wholesale rate is calculated as the rate(s) at which BPA is selling power to  
3 COUs, that is, the PFp rate (for general requirements, as defined in Section 7(b)(4) of the  
4 Northwest Power Act) and the NR rate (for power used to serve NLSL). 16 U.S.C.  
5 § 839e(c)(4). The IP rate begins by being set to the average of the PF and NR rates,  
6 weighted by sales to COUs at each rate and reflecting the DSI class load factor.

7  
8 **2.2.2.5.2 Typical Margin, Value of Reserves, and Net Industrial Margin**

9 As noted above, the DSI rate is set by adding the VOR Credit and typical margin to the  
10 applicable wholesale rate. The VOR Credit is calculated as described in Section 4.3.1.1.1  
11 below. The typical margin is calculated in Appendix A. The typical margin plus the VOR  
12 Credit yields the net industrial margin. *See* Power Rates Study Documentation, BP-26-  
13 FS-BPA-01A, Table 2.4.1. The net industrial margin is added to the applicable wholesale  
14 rate, and the result is multiplied by the forecast DSI load to determine the costs for the IP  
15 rate pool.

16  
17 **2.2.2.5.3 IP-PF Link 7(c)(2) Adjustment**

18 The IP-PF Link 7(c)(2) adjustment accounts for the difference between the revenues  
19 expected to be recovered from the DSIs at the final IP rate and the costs allocated to the  
20 rate. This difference, known as the 7(c)(2) delta, is allocated to non-DSI rates, primarily the  
21 PF rate. Because the allocation of the 7(c)(2) delta changes the PF and the NR rates,  
22 together forming the applicable wholesale rate upon which the IP rate is based, the 7(c)(2)  
23 delta must be recalculated. The interaction between the applicable wholesale rate and the  
24 IP rate has been reduced to an algebraic formula to approximate a solution, and then the  
25 RAM uses an intrinsic Excel function, “Goal Seek,” to converge on a solution for each year of  
26 the rate test period. *Id.*, Table 2.4.4.

1 **2.2.2.5.4 IP Floor Rate Verification**

2 Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers will  
3 not be less than the rates in effect for the contract year ending June 30, 1985 (the floor  
4 rate). 16 U.S.C. § 839e(c)(2). Accordingly, a test is performed to determine if the IP rate is  
5 at a level below the 1985 IP rate. If so, an adjustment is made that raises the IP rate to the  
6 floor rate and credits other customers with the increased revenue from the DSIs. If the  
7 IP rate is set at a level above the floor rate, no floor rate adjustment is necessary.

8  
9 The first step in calculating the floor rate is to apply the IP-83 Standard rate components  
10 to rate period (FY 2026-2028) DSI Billing Determinants. The resulting revenue figure is  
11 divided by total IP rate period energy loads to arrive at an average rate in mills per  
12 kilowatthour. This rate is reduced by an Exchange Cost Adjustment and a Deferral  
13 Adjustment, which were included in the IP-83 rate but are no longer applicable. Both  
14 adjustments are made on a mills-per-kilowatthour basis.

15  
16 In addition, the transmission component of the IP-83 rate is removed to allow a power-only  
17 floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total  
18 transmission costs in mills per kilowatthour from the IP-83 rate in the same manner as the  
19 Exchange Cost Adjustment and Deferral Adjustment are removed. The unit transmission  
20 component is determined by dividing total transmission costs in the IP-83 rate by the total  
21 Energy Billing Determinants for that rate period. *See* Power Rates Study Documentation,  
22 BP-26-FS-BPA-01A, Table 2.4.6. These calculations result in an “undelivered” IP floor rate.  
23 The floor rate is applied to the current rate period DSI Billing Determinants to determine  
24 floor rate revenue. Revenue at the IP rates is compared to the revenue at the floor rate.  
25 Because revenue from the IP rate is greater than the floor rate revenue, no floor rate  
26 adjustment is necessary. *Id.*, Tables 2.4.6 and 2.4.7.

1 **2.3 Rate Modeling Iterations**

2 Several iterations—both within RAM2026 and between other models and RAM2026—are  
3 required before the ratemaking process is complete. These iterations ensure that the  
4 appropriate costs are computed and allocated consistent with the principles of the  
5 Northwest Power Act and TRM rate design.

6  
7 **2.3.1 Iterations Internal to the Model**

8 **2.3.1.1 Participation in the Residential Exchange Program**

9 For a utility participating in the REP to be eligible to receive REP benefits, the modeling  
10 requires that the applicable Base Pfx rate be less than a participating utility’s ASC. The  
11 applicable Base Pfx rate is either 1) the Base Tier 1 Pfx rate for COUs, or 2) the Base Pfx  
12 rate for IOUs (the difference being the inclusion of Tier 2 costs in the Base Pfx rate for  
13 IOUs). If a utility has an ASC less than its applicable Base Pfx rate, that utility is ineligible  
14 to receive financial benefits through the REP as an “active” exchanger for the upcoming rate  
15 period. See Section 2.2.2.2 above. RAM2026 uses a macro loop feature to test whether, for  
16 each year of the exchange period, each utility with an ASC qualifies for REP benefits. If a  
17 utility does not qualify, a binary index is used to exclude it, and if it does qualify, the index  
18 is set to include it. This test is performed such that the exchange resource costs are  
19 calculated including the resources purchased from only REP-active participants. It is  
20 performed before the Rate Directives Step of the 7(c)(2) linking of the IP and PF rates, the  
21 determination of rate protection, and subsequent reallocation of rate protection.

22  
23 **2.3.1.2 Costs of Rate Discounts**

24 The costs of the LDD and IRD are included in the Composite customer charge, but these  
25 costs are jointly determined with other aspects of ratemaking, such as REP benefits and IP  
26 and NR revenues. Because these revenues change depending on the costs of the LDD and

1 IRD programs, the amounts of these costs are determined through iteration in the model.  
2 As explained in Sections 2.1.4.3-4 above, RAM2026 computes the cost of the LDD program  
3 by applying the applicable discount percent to the forecast billing determinants, which are  
4 then applied to the rates. The IRD program cost is based on a historical percentage and a  
5 resulting \$/MWh rate discount, which is then applied to internally computed customer  
6 charges. For each iteration, the appropriate charges are applied and new discount costs are  
7 computed. These new discount costs are allocated in the COSA Step, whereupon the Rate  
8 Directives Step and rate design under the TRM are performed again. New charges and  
9 rates are computed, which are again applied to the discount calculations. The iterative  
10 process continues until convergence.

### 11 12 **2.3.1.3 Contract Formula Rates**

13 If a power sales contract rate was agreed to be tied contractually to a result of rate  
14 modeling, an iterative approach might be required to solve for the amount of revenue to be  
15 credited in the COSA Step. No internal iterations are currently required to model contracts  
16 at formula rates.

### 17 18 **2.3.2 Iterations External to the Model**

19 Some aspects of the ratemaking process are dependent upon the rates computed in  
20 RAM2026. Many of these dependencies have been integrated within RAM2026, as  
21 described above. Other dependencies are simply too large to incorporate into one model.  
22 Thus, external iterations must be performed before rates can be finalized.

#### 23 24 **2.3.2.1 Consumer-Owned Utility Average System Costs**

25 The ASCs of COUs participating in the REP are based in part on the cost of power purchased  
26 from BPA at rates determined in RAM2026. Moreover, the COU customer's FRP Surcharge

1 Amount is dependent upon the COU's Non-Slice Tier 1 Cost Allocator (TOCA). These two  
2 factors require a recomputation of ASCs for COUs based on the PFp rate level and the FRP  
3 Surcharge Amount. This iteration is manually performed between RAM2026 and the ASC  
4 forecast model. Revised ASCs are included in RAM2026, and rate levels are recomputed  
5 until the results converge.

### 6 7 **2.3.2.2 Risk Analysis and Mitigation: PNRR**

8 As discussed in Section 2.1.5.4 above, the amount of PNRR added to rates to meet the TPP  
9 standard is the result of an iterative process among three models: RAM2026, RevSim, and  
10 ToolKit. See Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4. The iterative  
11 process is initiated with a \$0 seed value for PNRR in the revenue requirement used in  
12 RAM2026. The resultant rates are used in RevSim to produce distributions of net revenues.  
13 These distributions are then used in the ToolKit to measure TPP. If the TPP standard is not  
14 met, iterations are run using updated PNRR values until PNRR just satisfies the TPP  
15 standard. Because this portion of PNRR for the BP-26 rates is determined to be zero, no  
16 iteration is required.

### 17 18 **2.3.2.3 Revised Revenue Test**

19 The revised revenue test is described in the Power Revenue Requirement Study, BP-26-FS-  
20 BPA-02, Section 3.3. The revised revenue test demonstrates that the BP-26 rates are  
21 sufficient to recover the revenue requirement, and no further rate adjustment is needed.

### 3. RATE DESIGN AND COST ALLOCATION

#### 3.1 Introduction

BPA follows the rate-setting directives of Section 7 of the Northwest Power Act. As explained in the legislative history of that Act, the rate directives govern the amount of revenue the Administrator collects from each class of customers, not the rate form. *See, e.g.,* H.R. Rep. No. 96-976, 2d Sess., pt. I, at 69 (1980). Northwest Power Act Section 7(e) reserves rate design (how the revenue is collected) to the Administrator.

Section 7(e) states:

Nothing in this chapter prohibits the administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

16 U.S.C. § 839e(e). Rate design uses the results of the cost and credit allocations of the COSA, as modified by the rate directives, to develop the rate components that will recover the costs allocated to each rate pool. Thus, rate design is applied after BPA has allocated its total power revenue requirement to the five rate pools discussed earlier: Priority Firm Public Power (PFp), Priority Firm Exchange Power (PFx), Industrial Firm Power (IP), New Resource Firm Power (NR), and Firm Power and Surplus Products and Services (FPS). Rate design does not change the amount of the revenue requirement allocated to each of the five rate pools. Rather, rate design determines how the revenue requirement is collected through rates for each of the five rate pools. Rate design resolves the revenue collection within a particular rate pool and distinguishes between different types of service and power consumption of individual wholesale power customers. Rate design also conveys price signals to customers to encourage more efficient power usage, differentiating between the relative market values of the products and services BPA offers to its customers.

1 Based on the results of the Rate Directives Step, RAM2026 designs rates for each rate pool.  
2 For the PFX rate, the IP rate, and the NR rate, the rate design from the model can be applied  
3 without further processing.  
4

### 5 **3.2 PFp Rates**

6 The rate design for the PFp rate is established in the TRM. *See* TRM, BP-12-A-03. As  
7 described in the TRM, the PFp rate design includes two tiers and different products within  
8 each tier. The costs and credits are allocated to the Tier 1 and Tier 2 cost pools based upon  
9 the principle of cost causation. While the TRM cost allocations do not change the costs  
10 allocated to the PFp rate pool, they do assign cost responsibility to the rates paid by  
11 customers purchasing the PFp products offered in the CHWM contracts: Load Following,  
12 Slice/Block, Block, and Tier 2. *Id.*  
13

14 The TRM specifies that all costs and credits constituting BPA's PFp revenue requirement be  
15 allocated to one of four customer cost pools: Composite, Non-Slice, Slice, or Tier 2. The  
16 Tier 2 cost pool is further divided into Short-Term, Load Growth, and Vintage cost pools, if  
17 any sales are being forecast in those cost pools. *Id.* After reflecting the cost allocations to  
18 other rate pools, the end result of the TRM cost allocations is that the total costs allocated  
19 to the four customer charge cost pools will equal the total costs allocated to the PFp rate  
20 pool after the COSA Step and the Rate Directives Step. Thus, the TRM cost allocations  
21 neither increase nor decrease the cost allocations to the PFp rate pool after the Rate  
22 Directives Step. A mathematical proof is included in RAM2026 that shows that the revenue  
23 requirement allocated to the PFp rate pools in the COSA equals the revenue collected from  
24 the seven cost pools under the PFp tiered rate design. *See* Power Rates Study  
25 Documentation, BP-26-FS-BPA-01A, Tables 3.1.7.1 and 3.1.7.2.  
26

1 While the TRM cost allocations do not change the costs allocated to the PFp rate pool, they  
2 do assign cost responsibility to the rates paid by customers purchasing the three primary  
3 products offered in the CHWM contracts: Load Following, Slice/Block, and Block. In  
4 addition, the TRM cost allocations recognize that, even though the rate-setting  
5 methodology described in this section is performed as if the REP were an actual purchase  
6 and sale of power, at this point in the rate-setting process the PFp rate can be determined  
7 based on its allocated share of the total REP benefit costs, rather than exchange resource  
8 costs and PFx revenues.

9  
10 The sections below detail the calculation of PFp rates consistent with the TRM.

### 11 12 **3.2.1 PFp Tier 1 Costs**

#### 13 **3.2.1.1 Composite Costs**

14 The Composite cost pool includes all Tier 1 costs and credits that are not otherwise  
15 allocated to the Non-Slice and Slice cost pools. The Composite cost pool forms the cost  
16 basis for the Composite Customer Charge, which is paid by all preference customers with  
17 CHWM contracts. Generally speaking, all costs associated with FBS resource costs,  
18 exchange resource costs (net of exchange program revenues), new resource costs,  
19 conservation costs, BPA program costs, and power transmission costs not otherwise  
20 allocated to the Non-Slice or Slice cost pools are allocated to the Composite cost pool.

21  
22 In addition to the costs from expense and capital programs (as outlined in the Power  
23 Revenue Requirement Study, BP-26-FS-BPA-02), significant ratemaking costs allocated to  
24 the Composite cost pool are as follows:

- 25 • Costs of the IRD and LDD programs.

- 1 • Net costs associated with the REP:
  - 2 ○ Costs are calculated using the ASC and exchange load for each qualifying REP
  - 3 participant, net of
  - 4 ○ Revenues that are calculated at the PFX Rates, incorporating REP Surcharges.
- 5 • System augmentation costs required to achieve annual load-resource balance.

6 *See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.1.1.*

### 8 **3.2.1.2 Non-Slice Costs**

9 The Non-Slice cost pool includes only those costs and credits that are specifically and  
10 uniquely attributed to the Load Following and Block products (including the Block portion  
11 of the Slice/Block product). Tier 1 costs and credits, primarily secondary revenues that are  
12 not associated with the Slice product, are allocated to the Non-Slice cost pool. The Non-  
13 Slice cost pool forms the cost basis for the Non-Slice customer rate, which is paid by  
14 preference customers that have selected the Load Following product or the Block product,  
15 and the Block purchases under the Slice/Block product. Significant Non-Slice costs include:

- 16 • Balancing power purchase costs required to serve the monthly/diurnal loads of
- 17 Load Following customers.
- 18 • Hedging costs associated with winter-shaping or locational swapping that result in
- 19 changes to anticipated secondary revenues.
- 20 • Transmission costs incurred to deliver secondary sales.
- 21 • Costs (or credits) associated with the Composite interest obligation when financial
- 22 reserves available for Power are less than the \$570.3 million starting balance of the
- 23 reserves at the inception of the Slice product offering.

24 *See id., Table 3.1.1.2.*

1 **3.2.1.3 Slice Costs**

2 The Slice cost pool includes only those costs and credits that are specifically and uniquely  
3 attributed to the Slice product. Tier 1 costs and credits that are associated with the Slice  
4 product are allocated to the Slice cost pool. The Slice cost pool forms the cost basis for the  
5 Slice customer rate, which is paid by preference customers that have selected the  
6 Slice/Block product for their Slice purchases. In the BP-26 rates there are no costs  
7 allocated to this cost pool. *Id.*

8  
9 **3.2.2 PFp Tier 2 Costs**

10 Costs and credits that are associated with the sale of power to serve a customer's Above-  
11 RHWL Load are allocated to Tier 2 cost pools. The primary costs allocated to a Tier 2 cost  
12 pool are the FCRPS and/or purchased power costs discussed in Section 3.2.2.1, including  
13 the cost of real power losses, designated by BPA as being for this purpose discussed in  
14 Section 3.2.2.1.1. In addition to power purchase costs, Tier 2 cost pools recover Resource  
15 Support Services (RSS), overhead costs, and other BPA costs that are not necessarily  
16 incurred solely for the purpose of serving Above-RHWL Load, but support making such  
17 sales. The initial allocation of these other costs is to either the Composite cost pool or the  
18 Non-Slice cost pool. Therefore, a portion of these other costs is allocated to Tier 2 cost  
19 pools. Tier 2 rates are set to recover costs within the respective Tier 2 cost pool. The Tier  
20 2 rate can be broken down on a dollars per megawatt-hour basis and consists of an energy  
21 component plus four adders: 1) Transmission Scheduling Service (TSS) costs; 2) capacity;  
22 3) losses; and 4) overhead costs.

23  
24 For BP-26, Tier 2 customers taking either the Tier 2 Short-Term Rate or Load Growth Rate  
25 will have the option to elect between a fixed-rate option (default election) or a formula-rate  
26 option. These two options speak only to the energy component portion of the Tier 2 rate,

1 and the four adders are the same in both options. *See* 2026 Power Rate Schedules and  
2 GRSPs, BP-26-A-01-AP01, PF-26, § 2.2

3  
4 The CHWM contracts include the following Tier 2 rate alternatives: Load Growth, Vintage,  
5 and Short-Term. In FY 2026, FY 2027, and FY 2028, BPA will have sales of power only at  
6 the Tier 2 Short-Term and Load Growth rates; therefore, there are two Tier 2 cost pools:  
7 the Short-Term cost pool and the Load Growth cost pool. *See* Power Rates Study  
8 Documentation, BP-26-FS-BPA-01A, Tables 3.5.1 and 3.5.2.

### 9 10 **3.2.2.1 Tier 2 Power Purchase Costs**

11 BPA does not have any committed firm power purchases for Tier 2 rate service for the  
12 FY 2026-2028 rate period and expects power sold at Tier 2 rates to be served with power  
13 from the FCRPS, including balancing purchases and uncommitted market purchases  
14 referred to as Tier 2 augmentation.

15  
16 For ratemaking purposes, RAM2026 assumes all power sourced from the federal system,  
17 including Tier 2 augmentation to serve Tier 2 load, will be priced using the fixed-rate  
18 option, which uses the forecast Aurora P10 market price plus the capacity adder. The  
19 Aurora P10 market price is based on the average of the annual Mid-C market price under  
20 firm generation conditions for each fiscal year informed by the Aurora model. *See* Power  
21 Market Price Study, BP-26-FS-BPA-04, Figure 5. The capacity adder is based on the  
22 Demand Rate. *See* Section 3.2.7 below.

23  
24 Tier 2 power purchase costs under the formula-rate option will use the observed Day  
25 Ahead Index—currently the Intercontinental Exchange (ICE) Mid-Columbia Day Ahead

1 Index—for the energy component of the Tier 2 Rate, plus the capacity adder. *See* Section  
2 3.2.7 below.

#### 3 4 **3.2.2.1.1 Tier 2 Real Power Losses**

5 Power purchased at Tier 2 rates is delivered power and thus must include the cost of real  
6 power losses. The cost of real power losses is calculated using the federal transmission  
7 loss factor from the BP-26 Power Loads and Resources Study, BP-26-FS-BPA-03,  
8 Section 3.1.7. The federal transmission loss factor represents the generation loss factor  
9 and must be adjusted to calculate the equivalent loss factor at the load. Given this  
10 adjustment, the real power loss factor is 3.21 percent. The power purchase costs include  
11 the cost of energy associated with this real power loss factor.

#### 12 13 **3.2.2.2 Tier 2 Resource Support Services**

14 A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS  
15 Adder is calculated by dividing Power Services' scheduling costs for the rate period by the  
16 total megawatthours actually scheduled in FY 2021, FY 2022, and FY 2023 to produce a  
17 yearly dollars per megawatthour value. Inputs to this calculation are shown in the Power  
18 Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.4. This value is multiplied by the  
19 amount of planned Tier 2 sales in each year for each Tier 2 alternative to produce the  
20 annual cost for the TSS Cost Adder included in each cost pool for each year. The Tier 2 TSS  
21 Cost Adder is one of the credits to the Composite cost pool summed in the RSS Revenue  
22 Credit. *See* Section 3.2.3.1.4 below. The calculated costs assigned to the Tier 2 rate cost  
23 pools in each year are shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A,  
24 Tables 3.5.1 and 3.5.2. The TSS rate adder for BP-26 is \$0.12/MWh for each year of the rate  
25 period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.9

1 Service at Tier 2 rates includes Transmission Curtailment Management Service (TCMS),  
2 which is a service that addresses transmission curtailment events. *See* Section 5.6.1.5  
3 below. To recover costs associated with TCMS, Tier 2 rates are subject to the Tier 2 Rate  
4 TCMS Adjustment, described in Section 5.4.6 below. For the BP-26 rate period, the Tier 2  
5 cost pools do not include any costs associated with financially flattening a resource because  
6 there are no variable, non-dispatchable resources assigned to the Tier 2 rates.

### 7 8 **3.2.2.3 Tier 2 Overhead Cost Adder**

9 Section 6.3.3 of the TRM, BP-12-A-03, describes an Overhead Cost Adder to be included as  
10 part of the Tier 2 rates. The overhead cost components used to calculate the Tier 2 Rate  
11 Overhead Cost Adder are listed in the Power Rates Study Documentation, BP-26-FS-  
12 BPA-01A, Table 3.6. The rate period total of these overhead costs is divided by BPA's total  
13 forecast of revenue-producing energy sales (PFp, IP, NR, FPS, Downstream Benefits and  
14 Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services  
15 Revenue, and Secondary sales). The result is a \$1.76/MWh adder for FY 2026, a  
16 \$1.90/MWh adder for FY 2027 and a \$1.93/MWh adder for FY 2028. *See* Power Rates  
17 Study Documentation, BP-26-FS-BPA-01A, Table 3.6. The dollars per megawatthour value  
18 in each year is multiplied by the number of planned sales in each year for each Tier 2  
19 alternative to produce the Overhead Cost Adder included in each Tier 2 cost pool for each  
20 year. The Tier 2 Overhead Cost Adder provides the revenue credit to the Composite cost  
21 pool (called Tier 2 Overhead Adjustment). *See* Section 3.2.5 below. The specific cost and  
22 sales values used in these calculations are shown in the Power Rates Study Documentation,  
23 BP-26-FS-BPA-01A, Table 3.6.

1 **3.2.2.4 Tier 2 Risk Adder**

2 Section 6.3.1 of the TRM, BP-12-A-03, describes a possible cost adder for risk when BPA  
3 has not made all the market purchases needed to serve the Tier 2 obligation. In accordance  
4 with the Tier 2 Risk Analysis described in the Power and Transmission Risk Study, BP-26-  
5 FS-BPA-05, Section 4.3.1, BPA does not have a discrete risk adder included in the Tier 2  
6 cost pools to cover Tier 2 risks in the BP-26 rate period. Instead of including a discrete risk  
7 adder for the remaining power purchase needs for the Tier 2 cost pools, BPA uses the  
8 Aurora P10 market price as a risk adjusted energy price for physically delivered power for  
9 the Tier 2 fixed-rate option. The combination of Aurora P10 prices, which inherently  
10 include an energy risk premium due to using a monthly 10<sup>th</sup> percentile firm generation  
11 forecast, and the addition of the capacity adder, mitigates Tier 2 risk from being recovered  
12 in Tier 1 rates. The capacity adder recovers the value of holding capacity in advance of  
13 delivery. See Section 3.2.7 below. Using this price construct for valuing Tier 2 power that  
14 has not been transacted for in advance helps ensure that Tier 2 rates are not subsidized by  
15 Tier 1 rates. See Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.3.1.

16  
17 The Tier 2 formula-rate option, when elected by customers, would move the energy price-  
18 forecast risk from BPA to those customers, so no additional risk provision would be  
19 necessary to ensure Tier 2 rates are not subsidized by Tier 1 rates.

20  
21 **3.2.2.5 Reallocated Power from Remarketing**

22 When power purchased for a Tier 2 rate pool exceeds Above-RHWM Loads, BPA remarkets  
23 the excess amounts and reallocates the value of that power to other Tier 2 pools if there is a  
24 need. Similarly, BPA remarkets excess non-federal amounts and reallocates and values that  
25 power in the same manner. The remarketing values are determined in accordance with  
26 Section 3.2.6 below.

1 The treatment of remarketing varies by the type of Above-RHWM service, including  
2 individual Tier 2 Cost Pools remarketing the energy. When non-federal resource and Tier 2  
3 Vintage amounts are remarketed, the value from such reallocations is credited to the  
4 individual customers, as required under the CHWM contract and the TRM, and as described  
5 in Section 5.7 below. When remarketing for the Tier 2 Load Growth pool, the value of  
6 remarketed energy is credited to the Tier 2 Load Growth pool and not directly to individual  
7 customers.

8  
9 The remarketed Tier 2 energy amounts are first reallocated to another Tier 2 pool with  
10 Above-RHWM Loads that exceed the power purchased for that pool, then purchased by  
11 BPA for augmentation if there is a need, or deemed surplus power available for resale into  
12 the market. *See* TRM, BP-12-A-03, § 3.4. Table 3.8 of the Power Rates Study  
13 Documentation, BP-26-FS-BPA-01A, summarizes the sources of remarketed power meeting  
14 the various Tier 2 loads. It includes remarketed power from other Tier 2 cost pools, if any,  
15 and remarketed power from non-federal resources with Diurnal Flattening Service (DFS), if  
16 any.

### 18 **3.2.3 PFp Tier 1 Revenue Credits**

19 The Composite and Non-Slice cost pools contain credits for revenues collected from other  
20 components of the PFp rates. All these rate design credits are necessary to ensure that the  
21 PFp rates do not over-collect the allocated revenue requirement and that the costs and  
22 credits have been allocated as specified in the TRM.

#### 24 **3.2.3.1 Composite Cost Pool Revenue Credits**

25 As stated in Section 3.2.1.1, the Composite cost pool includes all Tier 1 costs and credits  
26 that are not otherwise allocated to the Slice and Non-Slice cost pools. As described in

1 Section 2.1.6, revenue credits are directly assigned to the TRM cost pool according to cost  
2 causation principles at the same time the COSA steps are completed. Significant  
3 ratemaking credits allocated to the Composite cost pool after the ratemaking steps in  
4 Section 2 are completed include revenues BPA receives from the following:

- 5 • DSI customers
- 6 • Power sales under the NR rate schedule
- 7 • Capacity revenue from NR Energy Shaping Service (NR ESS)
- 8 • Capacity revenue associated with RSS
- 9 • Capacity revenue associated with the sale of Real Power Losses

#### 10

#### 11 **3.2.3.1.1 Revenues from DSI Customers**

12 These are forecast IP rate revenues consistent with sales forecasts from the Power Loads  
13 and Resources Study applied to the IP rate as determined in Section 4.3 below.

#### 14

#### 15 **3.2.3.1.2 Revenues from Power sales under the NR rate schedule**

16 These are forecast NR rate revenues.

#### 17

#### 18 **3.2.3.1.3 Revenues from NR Energy Shaping Service**

19 The New Resource Firm Power rate schedule includes NR ESS, which includes a capacity  
20 (demand) component. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A,  
21 Table 3.12. Forecast revenue from the capacity component of the NR ESS is credited to the  
22 Composite cost pool by means of the NR Revenue Credit. *See id.*, Table 2.3.6.

#### 23

#### 24 **3.2.3.1.4 Revenues from Resource Support Services**

25 BPA provides Resource Support Services (RSS) and related services, which generate  
26 revenue from preference customers. *See* Section 5.6 below. Revenues received from the

1 capacity components of RSS are credited to the Composite cost pool. For transparency  
2 purposes, BPA committed in the TRM to apply the applicable RSS to resources serving  
3 system augmentation needs (currently Klondike III) and to resources supporting the Tier 2  
4 rates, if appropriate. In these situations, the source of the RSS revenue credit to the  
5 Composite cost pool is provided through either an RSS adder to the system augmentation  
6 cost or an RSS cost allocated to a Tier 2 cost pool. Revenues provided by the energy  
7 components of RSS are credited to the Non-Slice cost pool. Unlike the capacity used to  
8 provide RSS, which operationally impacts the Slice/Block, Block, and Load Following  
9 products, the provision of RSS energy operationally impacts the Non-Slice products only  
10 (including the Block portion of the Slice/Block product).

11  
12 BPA committed in the TRM to apply RSS to resources serving RHWL Augmentation needs  
13 (e.g., Klondike III). The cost of Klondike III, a wind plant, is assigned to Tier 1  
14 Augmentation in the Composite cost pool. The TRM states that RSS pricing will be used to  
15 make certain federal resource acquisitions financially equivalent to a flat block. See TRM,  
16 BP-12-A-03, § 8. Tier 1 Augmentation is assumed to be in the shape of an annual flat block  
17 purchase for ratemaking purposes. See *id.* § 3.5. Because Klondike III's generation is  
18 variable and non-dispatchable, the RSS module of RAM2026 calculates a DFS capacity  
19 charge, a DFS energy charge, a Resource Shaping charge, and a TSS charge for Klondike III,  
20 and the resulting costs are allocated to the Composite cost pool. See Power Rates Study  
21 Documentation, BP-26-FS-BPA-01A, Table 3.11. The total annual RSS revenue credit for  
22 FY 2026-2028 is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A,  
23 Table 3.2.

24

1 **3.2.3.1.5 Capacity Revenue Associated with the Sale of Real Power Losses**

2 These are forecast revenues associated with the capacity portion of Real Power Losses  
3 settled financially. See Section 4.4.2.2 below (describing how the capacity cost for Real  
4 Power Losses is determined).

5  
6 **3.2.3.2 Non-Slice Cost Pool Revenue Credits**

7 As stated in Section 3.2.1.2, the Non-Slice cost pool includes all Tier 1 costs and credits that  
8 are not otherwise allocated to the Composite and Slice cost pools. As described in  
9 Section 2.1.6, revenue credits are directly assigned to the TRM cost pool according to cost  
10 causation principles as the COSA steps are completed. Significant ratemaking credits  
11 allocated to the Non-Slice cost pool after the ratemaking steps in Section 2 are completed  
12 include revenues BPA receives from the following:

- 13 • Secondary Energy (including Firm Surplus Secondary Sales)
- 14 • Load Shaping
- 15 • Demand
- 16 • Resource Shaping Charge (RSC)

17  
18 **3.2.3.2.1 Revenues from Secondary Energy**

19 These are revenues associated with non-firm secondary sales and Firm Surplus Secondary  
20 Sales, as calculated in the Power Market Price Study, BP-26-FS-BPA-04, but excluding  
21 secondary energy sold under the Slice product as described in Section 2.1.6.9 above.

22  
23 **3.2.3.2.2 Revenues from Load Shaping**

24 The Load Shaping charge is designed to recover costs associated with shaping the firm  
25 output of the Tier 1 System Resources to the monthly/diurnal shape of a customer's Tier 1  
26 load. The Load Shaping charge applies to Non-Slice products, Block (including the Block

1 portion of the Slice/Block product), and Load Following, but not the Slice portion of the  
2 Slice/Block product. As stated in Section 5.2 of the TRM, BP-12-A-03, forecast revenue  
3 from the Load Shaping charge is credited to the Non-Slice cost pool by means of the Load  
4 Shaping Revenue Credit. *See* Section 4.1.1.3 below.

#### 6 **3.2.3.2.3 Revenues from Demand**

7 The Priority Firm Demand Charge is designed to send a price signal to a limited portion of a  
8 customer's overall demand on BPA and applies to customers purchasing Load Following  
9 and Block with Shaping Capacity products. As stated in Section 5.3 of the TRM, BP-12-A-03,  
10 forecast revenue from the Demand Charge is credited to the Non-Slice cost pool by means  
11 of the Demand Revenue Credit. *See* Section 4.1.1.2 below.

#### 13 **3.2.3.2.4 Revenues from the Resource Shaping Charge**

14 All balancing purchase costs, either resource or load, are allocated to the Non-Slice cost  
15 pool. The RSC collects additional revenues for balancing purchase costs associated with  
16 balancing resources against a flat annual block. *See* Sections 5.6.1.2 and 5.6.1.3. To pair  
17 cost allocation with revenue collection of balancing purchase costs, the forecast RSC  
18 revenue credit is applied to the Non-Slice cost pool.

19  
20 BPA committed in the TRM to apply RSC to resources serving system RHWL Augmentation  
21 needs (*e.g.*, Klondike III) and to resources supporting the Tier 2 rates in order to make  
22 these acquisitions financially equivalent to a flat block. *See* TRM, BP-12-A-03, § 8. In these  
23 situations, the source of the RSC revenue credit is provided through either an RSC adder to  
24 the system augmentation cost or an RSC adder within a Tier 2 cost pool. The forecast  
25 annual RSC revenue credit for FY 2026-2028 is shown in the Power Rates Study  
26 Documentation, BP-26-FS-BPA-01A, Table 3.2.

1 **3.2.4 Rate Design Adjustments Made Between Tier 1 Cost Pools**

2 Once costs and rate design revenue credits have been balanced with the revenue  
3 requirement, additional adjustments to the PFp cost pools are made to the extent necessary  
4 to avoid cost shifts among products (Load Following, Block, and Slice/Block) and tiers  
5 (Tier 1 and Tier 2). These rate design adjustments move dollars from one cost pool to  
6 another through equal credits and debits and do not change the total revenue requirement  
7 for PFp. These rate design adjustments include three adjustments made within Tier 1 and  
8 one adjustment made between Tier 1 and Tier 2. See Section 3.2.5 below. The three types  
9 of adjustments made within Tier 1 are the 1) Transmission Loss Adjustments; 2) Firm  
10 Surplus and Secondary Adjustments from Unused RHW; and 3) Balancing Augmentation  
11 Load Adjustments. The adjustment made between Tier 1 and Tier 2 is the Tier 2 Overhead  
12 Adjustment. See Section 3.2.5 below. The TRM allocation of these rate design adjustments  
13 is shown in the Power Rates Study Documentation, BP-26-FS-BP-01A, Tables 3.1.6.1 and  
14 3.1.6.2.

15  
16 **3.2.4.1 Transmission Loss Adjustments**

17 Transmission Loss Adjustments provide a credit to the Composite cost pool and an equal  
18 debit to the Non-Slice cost pool based on Non-Slice transmission losses. Transmission Loss  
19 Adjustments address the different accounting of transmission losses for the Slice/Block  
20 and Non-Slice products. The Non-Slice products and the Block portion of the Slice/Block  
21 product are delivered to the purchaser's load service area, while the Slice product is  
22 delivered to the purchaser at BPA's generation bus bar. The cost of generating the real  
23 power losses for the transmission of Non-Slice sales is included in the Composite cost pool.  
24 Conversely, the cost of generating the real power losses for the transmission of Slice sales  
25 is borne by the purchaser.

1 Transmission Loss Adjustments transfer the cost of generating the real power losses for  
2 the transmission of Non-Slice PF sales from the Composite cost pool to the Non-Slice cost  
3 pool. Transmission Loss Adjustments are calculated by multiplying the network losses  
4 associated with the Non-Slice PF products, including the Block portion of the Slice/Block  
5 product, by the average Slice and Non-Slice Tier 1 rate. The calculation and result of the  
6 Transmission Loss Adjustments are shown in the Power Rates Study Documentation,  
7 BP-26-FS-BPA-01A, Table 3.1.3.

#### 8 9 **3.2.4.2 Firm Surplus and Secondary Adjustments from Unused RHW**

10 Unused RHW occurs when a customer's Forecast Net Requirement is less than its RHW.  
11 Firm Surplus and Secondary Adjustments from Unused RHW reallocate costs between  
12 the Composite cost pool and the Non-Slice cost pool.

13  
14 Unused RHW reduces the need for system augmentation and/or increases firm power  
15 available for sale in the market. The reduced augmentation expenses and/or increased  
16 firm power market revenues are reflected in three lines on the TRM cost table:

17 1) Augmentation, 2) Secondary Energy Credit, and 3) Balancing Purchases from RevSim.  
18 *See id.*, Tables 3.1.1.1-3. The Augmentation line is part of the Composite cost pool, and the  
19 Secondary Energy Credit and Balancing Purchases are part of the Non-Slice cost pool. To  
20 share the entire benefit of Unused RHW with all customers, the Composite and Non-Slice  
21 cost pools contain a Firm Surplus and Secondary Adjustment (from Unused RHW), which  
22 appears as a credit to the Composite cost pool and an equal and offsetting charge to the  
23 Non-Slice cost pool.

24  
25 Firm Surplus and Secondary Adjustments have two purposes. The first is to reflect the  
26 difference between the value of a flat annual block of system augmentation and the value of

1 the Unused RHWL when the Unused RHWL displaces augmentation. The difference  
2 between a flat annual block of system augmentation and the shape of the Unused RHWL  
3 is reflected in changes in the assumed balancing purchases and associated costs. These  
4 changes in balancing purchase costs are captured in the Non-Slice cost pool. A Firm  
5 Surplus and Secondary Adjustment reallocates the change in balancing purchase costs  
6 associated with the difference in value from the Non-Slice cost pool to the Composite cost  
7 pool.

8  
9 The second purpose of Firm Surplus and Secondary Adjustments is to reflect the full value  
10 of the Unused RHWL when the Unused RHWL creates firm surplus power. The revenue  
11 associated with this change in firm surplus power related to the Unused RHWL is reflected  
12 in the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary  
13 Adjustment reallocates this change in secondary revenues associated with the Unused  
14 RHWL from the Non-Slice cost pool to the Composite cost pool.

15  
16 The value of Unused RHWL consists of portions of RHWL Augmentation, Tier 1 System  
17 Firm Critical Output, and an associated portion of secondary energy. Each of these three  
18 components is valued at its respective price: the Augmentation price for the RHWL  
19 Augmentation component; the market price (as expressed by the Load Shaping rates) for  
20 the Tier 1 System Firm Critical Output component; and the market price (as expressed by  
21 the average price received for secondary sales) for the secondary component. The value of  
22 Unused RHWL (expressed in dollars per megawatthour) also will be calculated for use in  
23 the Slice True-Up of the Firm Surplus and Secondary Adjustments line item in the  
24 Composite cost pool. See *id.*, Table 3.1.2 (displaying the results and calculation of Firm  
25 Surplus and Secondary Adjustments from Unused RHWL and the dollar-per-  
26 megawatthour Slice True-Up value of Unused RHWL).

1 **3.2.4.3 Balancing Augmentation Load Adjustments**

2 As explained further in the subsections below, balancing augmentation load is 1) Above-  
3 RHWM Load that is forecast to be served at Load Shaping rates; 2) Above-RHWM Load that  
4 is no longer forecast to occur (net negative Load Shaping Billing Determinants); or  
5 3) changes to the Tier 1 System during the applicable Section 7(i) ratemaking process from  
6 that used to establish each customer’s allocation of the cost of the Tier 1 System during the  
7 applicable RHW Process.

8  
9 The sum total of these conditions is either a charge or credit to the Composite cost pool and  
10 an offsetting credit or charge, respectively, to the Non-Slice cost pool. *See id.*, Tables 3.1.6.1  
11 and 3.1.6.2.

12  
13 **3.2.4.3.1 Above-RHWM Load Forecast to be Served at Load Shaping Rates**

14 This first condition occurs when Above-RHWM Load is forecast to be served at Load  
15 Shaping rates either 1) when a Load Following customer’s annual Above-RHWM Load is  
16 less than 8,760 MWh and the Load Following customer made no alternative election to  
17 serve its Above-RHWM Load, or 2) when Above-RHWM Load is determined in the RHW  
18 Process and the load forecast is updated during the rate proceeding to reflect the forecast  
19 of a larger load. When either 1) or 2) is true and the amount of system augmentation  
20 purchases is equal to or greater than the amount of balancing augmentation load, the  
21 acquisition costs attributable to supplying balancing augmentation load are included as a  
22 system augmentation expense in the Composite cost pool. The revenue from supplying  
23 balancing augmentation load is credited to the Non-Slice cost pool through the Load  
24 Shaping charge revenue credit. Without a Balancing Augmentation Load Adjustment, only  
25 Non-Slice customers would receive credits through an increased Load Shaping Charge  
26 revenue credit, but both Slice and Non-Slice customers would bear the cost of increased

1 system augmentation expense. The Balancing Augmentation Load Adjustment corrects this  
2 situation with a credit to the Composite cost pool and an equal debit to the Non-Slice cost  
3 pool.

4  
5 This condition causes the sum of Load Shaping Billing Determinants to be positive.  
6 Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are  
7 calculated as the lesser of 1) the sum of the Load Shaping Billing Determinants for each  
8 fiscal year, or 2) the incurred system augmentation amount for each fiscal year. The result  
9 is multiplied by the augmentation price for the respective fiscal year.

#### 10 11 **3.2.4.3.2 Above-RHWM Load No Longer Forecast to Occur**

12 The second condition that creates a change to balancing augmentation occurs when the  
13 load forecast decreases from the forecast used in the RHWM Process. When this condition  
14 occurs, there is a reduction in system augmentation expenses from what otherwise would  
15 have occurred. The Composite cost pool would have received an implicit reduction in costs  
16 due solely to load variation attributable to Non-Slice customer loads. In this case, the  
17 Balancing Augmentation Adjustment is a debit to the Composite cost pool and an equal  
18 credit to the Non-Slice cost pool.

19  
20 All other things being equal, this condition causes the sum of the Load Shaping Billing  
21 Determinants to be negative. Balancing Augmentation Load Adjustments to the Composite  
22 and Non-Slice cost pools are calculated as the greater of 1) the sum of the Load Shaping  
23 Billing Determinants for each fiscal year, or 2) the avoided augmentation amount  
24 (expressed as a negative number) for each fiscal year. The result is multiplied by the  
25 augmentation price for the respective fiscal year.

1 **3.2.4.3.3 Changes to the Tier 1 System During the Applicable 7(i) Rate-setting**  
2 **Process**

3 The third condition occurs when the forecast of Tier 1 System output is updated from the  
4 Tier 1 System forecast in the RHW process. Any change in the Tier 1 System that changes  
5 the amount of System Augmentation will cause either a cost or a credit to be included in the  
6 Balancing Augmentation Load Adjustment. System Augmentation is allocated to the  
7 Composite cost pool, and therefore any change to the Tier 1 System which changes the cost  
8 allocated to this pool requires an adjustment. The cost or credit is included as an addition  
9 to the Balancing Augmentation Adjustment rather than in the Balancing Power Purchase  
10 costs computed in RevSim. Tier 1 System Firm Critical Output changes will increase or  
11 decrease, on an annual average basis, the amount of augmentation required, and such  
12 augmentation is considered Balancing Power Purchases under the TRM.

13  
14 RevSim computes Balancing Power Purchase costs after load-resource balance has been  
15 achieved under firm generation conditions. See TRM, BP-12-A-03, § 3.3. If the Tier 1  
16 System increases relative to the RHW process Tier 1 System output, the Non-Slice cost  
17 pool will receive a credit for this additional anticipated energy equal to the avoided System  
18 Augmentation expense due to the change. Alternatively, if the Tier 1 System decreases, the  
19 Non-Slice cost pool will be charged for the reduction in anticipated energy to the extent  
20 that the reduction contributed to a higher System Augmentation expense. Equal and  
21 offsetting costs/credits are applied to the Composite cost pool. See Power Rates Study  
22 Documentation, BP-26-FS-BPA-01A, Tables 3.1.6.1 & 3.1.6.2.

23  
24 Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are  
25 calculated as the avoided augmentation amount for each fiscal year multiplied by the  
26 augmentation price for the respective fiscal year.

1 **3.2.5 Rate Design Adjustment Made Between Tier 1 and Tier 2 Cost Pools**

2 The Tier 2 Overhead Adjustment Credits the Composite cost pool for the overhead costs  
3 charged to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost  
4 Adder, which reflects a proportionate share of BPA’s total overhead costs. *See Section*  
5 *3.2.2.3 above.* The Tier 2 Overhead Adjustment credited to the Composite cost pool is  
6 equal to the sum of the Overhead Cost Adders charged to all of the Tier 2 cost pools. The  
7 calculation of the Tier 2 Overhead Adjustment for FY 2026-2028 is shown in the Power  
8 Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.6.

9  
10 **3.2.6 Remarketing Value**

11 The Remarketing Value is used to price any uncommitted market purchases associated  
12 with all forms of firm system augmentation including Tier 1 and Other Augmentation in  
13 addition to valuing all forms of remarketing (Tier 2, non-federal, and RRS). *See Section 5.7*  
14 *below.* The Remarketing Value may differ by fiscal year. *See Power Rates Study*  
15 *Documentation, BP-26-FS-BPA-01A, Table 3.10.*

16  
17 The Remarketing Value is calculated for each fiscal year using the annual Aurora P10 price  
18 with negative prices removed plus the capacity adder. The Aurora P10 market price is  
19 based on the average of the annual Mid-C Market Price under firm generation conditions  
20 for each Fiscal Year. *See Power Market Price Study, BP-26-FS-BPA-04, Figure 5.* The  
21 capacity adder is described in Section 3.2.7 below.

22  
23 **3.2.7 Capacity Adder**

24 The capacity adder is the cost of capacity associated with an advanced sale of firm power.  
25 The \$/MWh capacity adder is calculated using the annual Demand Rate multiplied by 1,000  
26 to convert to megawatthours, then multiply by 12 to reflect total months in a year which is

1 then divided by 8,760 hours in a non-leap year or 8,784 in a leap year. See Power Rates  
2 Study Documentation, BP-26-FS-BPA-01A, Table 3.9.

### 4 **3.2.8 Allocation of New Expenses and Credits**

5 BPA will allocate New Expenses or New Credits, as defined in the TRM, to the cost pools  
6 based on the cost allocation principles stated in Section 2 of the TRM. TRM Section 2.3  
7 states that BPA will propose an allocation of the New Expenses and New Credits, if any, to  
8 the appropriate cost pools in the next applicable Section 7(i) process. TRM, BP-12-A-03,  
9 § 2.3.

10  
11 For BP-26, four new expenses and one new credit line were added to RAM2026. The new  
12 costs and credit line, including the designated cost pool and PF public rate design cost pool,  
13 are listed below:

- 14 1. Amortization of P2IP Settlement Payments, a composite cost. 2.
- 15 2. Long Term Funding Agreements (Accords), a composite cost
- 16 3. Long Term Funding Agreements (Accords), a composite cost.
- 17 4. Payments for Litigation of Stay Agreements (P2IP), a composite cost.
- 18 5. Other Augmentation, a new resource cost.
- 19 6. Tiered Rates Adjustment, a composite credit.

20  
21 Consistent with the Update to BPA's BP-26 Cost Projections, issued on July 14, 2025, cost  
22 projections in power rates associated with the Memorandum of Understanding filed on  
23 December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v.*  
24 *National Marine Fisheries Service*, 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were  
25 removed. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5.

1 **4. RATE SCHEDULES**

2  
3 BPA’s power rate schedules state the applicability of each rate schedule to the products  
4 that BPA offers, the rates for the products, the billing determinants to which the rates are  
5 applied, and the sections of the GRSPs that apply to each rate schedule. The power rate  
6 schedules described in this section are presented in their entirety in the 2026 Power Rate  
7 Schedules and GRSPs, BP-26-A-01-AP01.

8  
9 **4.1 Priority Firm Power (PF-26) Rate**

10 The PF-26 rate applies to sales of firm (continuously available) power to be used within the  
11 Pacific Northwest by public bodies, cooperatives, federal agencies, and investor-owned  
12 utilities participating in the REP. The PF-26 rate schedule is available for the contract  
13 purchase of Firm Requirements Power pursuant to Section 5(b) of the Northwest Power  
14 Act. 16 U.S.C. § 839c(b). Utilities participating in the REP under Section 5(c) of the  
15 Northwest Power Act may purchase PF power pursuant to a Residential Purchase and Sale  
16 Agreement (RPSA) or Residential Exchange Program Settlement Implementation  
17 Agreement (REPSIA). 16 U.S.C. § 839c(c); *see* Section 8 below.

18  
19 The PF Public rate applies to firm requirements purchases under CHWM contracts and  
20 includes Tier 1 and Tier 2 charges. *See* Sections 4.1.1 and 4.1.2. Rates for firm  
21 requirements purchases under arrangements other than CHWM contracts include the  
22 PF Melded rate and the Unanticipated Load Service rate. *See* Sections 4.1.3 and 4.1.4.

23  
24 **4.1.1 PFp Tier 1 Charges**

25 The majority of PF Public revenue is collected from firm requirements power purchased at  
26 Tier 1 rates. Tier 1 charges (rates and billing determinants) apply to PF power purchased

1 to meet a customer’s RHWL Load. Tier 1 charges include:

- 2 • Customer Charges (Composite, Non-Slice, Slice)
- 3 • Demand Charge
- 4 • Load Shaping Charge

5  
6 PF Public Tier 1 Non-Slice rates are subject to risk adjustments during the Rate Period  
7 pursuant to the Power Cost Recovery Adjustment Clause (Power CRAC); the Power  
8 Reserves Distribution Clause (Power RDC); and the Power FRP Surcharge. *See* Section 5.2  
9 below. Any adjustments to rates and GRSPs during the Rate Period due to such risk  
10 adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs.  
11 *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.1.4.

#### 13 **4.1.1.1 Customer Charges**

##### 14 **4.1.1.1.1 Customer Charge Rates**

15 Rates for the Composite, Non-Slice, and Slice customer charges are expressed as dollars per  
16 1 percentage point of Billing Determinant (TOCA, Non-Slice TOCA, or Slice percentage,  
17 respectively). Each of the three rates is calculated by dividing the total costs allocated to  
18 each cost pool, as described in Section 3.2.1 above, by the sum of the respective forecast  
19 Billing Determinants, as described in Section 4.1.1.1.2 below. The quotient of that  
20 calculation is then divided by 12 to yield a monthly rate per 1 percent of the applicable  
21 Billing Determinant.

22  
23 The resulting monthly rates are shown in Power Rates Study Documentation, BP-26-  
24 FS-BPA-01A, Table 3.1.6.3.

1 **4.1.1.1.2 Customer Charge Billing Determinants**

2 The TOCA is the customer-specific Billing Determinant applied to the Composite Customer  
3 rate. The majority of BPA's costs to be collected through PF rates are allocated among  
4 customers through the TOCA. Each customer's annual TOCA percentage is calculated by  
5 dividing the lesser of an individual customer's RHWMM or its Forecast Net Requirement by  
6 the total of the RHWMMs for all PFp customers.

7  
8 The Forecast Net Requirement and RHWMM for the individual customer and the sum of  
9 RHWMMs for all customers are expressed in average annual megawatts. The total of the  
10 RHWMMs for all customers is shown in Power Rates Study Table 1, and the sum of TOCAs  
11 used for FY 2026-2028 is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A,  
12 Table 3.1.6.3.

13  
14 The Non-Slice TOCA is the customer-specific billing determinant applied to the Non-Slice  
15 Customer rate. The Non-Slice TOCA is equal to a customer's TOCA if the customer is  
16 purchasing the Load Following or Block product. The Non-Slice TOCA for customers  
17 purchasing the Slice/Block product is computed as the difference between the customer's  
18 TOCA and its Slice percentage. The forecast sum of Non-Slice TOCAs used for FY 2026-  
19 2028 is shown in *id.*, Table 3.1.6.3.

20  
21 The Slice percentage is the customer-specific billing determinant applied to the Slice  
22 Customer rate. Initial Slice percentages appear in Exhibit J of each Slice customer's CHWM  
23 contract. These percentages can be adjusted each year pursuant to TRM Section 3.6, and  
24 the final Slice percentage is established in Exhibit K of the customer's CHWM contract.  
25 TRM, BP-12-A-03, § 3.6.

1 **4.1.1.2 Tier 1 Demand Charge**

2 **4.1.1.2.1 Demand Charge Rates**

3 Demand rates are based on the annual fixed costs (capital and operations and maintenance  
4 [O&M]) of a marginal capacity resource, a Wärtsilä 18V50SG reciprocating generator, as  
5 determined by the Northwest Power and Conservation Council’s (NPCC or Council)  
6 Microfin model. For the BP-26 Rate Period, a dampening methodology is applied to the  
7 demand rate in order to allow half of the increase that would otherwise be indicated by the  
8 model. The application of this dampening methodology is discussed below.

9  
10 The Microfin model estimates the nominal all-in capital costs of a Wärtsilä 18V50SG  
11 reciprocating generator with a 2026 in-service date. The all-in capital cost under these  
12 specifications is \$1,798/kW as shown in Power Rates Study Documentation, BP-26-  
13 FS-BPA-01A, Table 4.1.

14  
15 The projected debt payment on the \$1,798/kW fixed capital costs is estimated at  
16 \$101.32/kW/yr., based on a cost of debt of 3.79 percent financed over 30 years. The plant  
17 is assumed to be owned by a publicly owned utility with BPA-backed bonds. The cost of  
18 debt is from BPA’s FY 2026 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. *See*  
19 *Power Revenue Requirement Study Documentation, BP-26-FS-BPA-02A, § 6, FY 2024*  
20 *Interest Rate and Inflation Forecast Memorandum.*

21  
22 The cost of fixed O&M included in the demand rate calculation is obtained from the  
23 Microfin model. The calculation of the demand rate uses the Microfin model’s estimate of  
24 \$5/kW/yr. escalated to 2026, 2027, and 2028 dollars using the 2016-to-2023 average  
25 (seven-year) rate of 3.18 percent calculated from Implicit Price Deflators from the

1 U.S. Bureau of Economic Analysis. The three-year average annual cost for fixed O&M is  
2 \$7.05/kW/yr. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1.

3  
4 Insurance and fixed fuel costs are also included in the calculation of the demand rate. The  
5 average annual insurance cost of \$4.27/kW/yr. is calculated based on 0.25 percent of the  
6 mid-year assessed value obtained from the Council's Microfin model. The average annual  
7 fixed fuel cost assumed in the demand rate calculation is \$27.76/kW/yr. The fixed fuel cost  
8 is estimated using Microfin's lifetime average rate of 8,797 Btu/kWh applied to the average  
9 of the existing eastside and westside Pacific Northwest fixed fuel costs for the applicable  
10 fiscal year. *Id.*

11  
12 The average annual expense as estimated by the model is \$140.40/kW. The previous  
13 BP-24 calculated average annual expense, using the same model, was \$114.54/kW.  
14 Applying the dampening methodology described above, half of the increase is allowed,  
15 resulting in a dampened value of \$127.47/kW. *See* Power Rates Study Documentation,  
16 BP-26-FS-BPA-01A, Table 4.1, line 30. This annual value is shaped into the 12 months of  
17 the year using the shape of the Heavy Load Hours (HLH) Load Shaping rates, resulting in  
18 demand rates specific to each month. *See* Power Rates Study Documentation, BP-26-  
19 FS-BPA-01A, Table 4.1; 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26,  
20 § 2.1.2.1.

#### 21 22 **4.1.1.2.2 Demand Charge Billing Determinant**

23 The Demand Billing Determinant applies to customers purchasing the Load Following and  
24 Block with Shaping Capacity products. TRM Sections 5.3.1-5 contain a detailed explanation  
25 of how to calculate the customer-specific Demand Billing Determinant, which is only a

1 limited portion of a customer's overall demand on BPA. TRM, BP-12-A-03. The following  
2 discussion summarizes the TRM explanation.

3  
4 Four quantities are used in calculating a PFp customer's Demand Charge Billing  
5 Determinant: 1) the Tier 1 Customer's System Peak (CSP); 2) the average amount of a  
6 customer's electric load (measured in average kilowatts) that was served at Tier 1 rates  
7 during the HLH of a month; 3) the customer's Contract Demand Quantity (CDQ, expressed  
8 in kilowatts); and 4) any applicable Super Peak Credit as specified in a customer's CHWM  
9 contract.

10  
11 The Demand Billing Determinant is determined by measuring a customer's CSP and then  
12 subtracting the other three quantities. The Demand Billing Determinant calculation can  
13 never result in a negative billing determinant; if the calculation results in a value less than  
14 zero, the Billing Determinant is deemed to be zero.

15  
16 The Tier 1 CSP is equal to a customer's maximum Actual Hourly Tier 1 Load (measured in  
17 kilowatts) during the HLH of a month. Twelve CDQs are specified for each PFp customer in  
18 the customer's CHWM contract.

19  
20 The Super Peak Credit is determined pursuant to a customer's CHWM contract. If a  
21 customer does not supply the Super Peak amount listed in Section 9 of Exhibit A of its  
22 CHWM contract for any hour of the Super Peak Period, then the customer does not receive  
23 a Super Peak Credit for that month. The Super Peak Period for FY 2026-2028 is defined in  
24 the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP III.B.30.

1 There are two possible adjustments that may be made to a customer’s Demand Billing  
2 Determinant. The first is an adjustment to offset anomalous recovery load peaks that occur  
3 after a customer has had power restored to its service territory following a weather-related  
4 system outage or other extreme peak event. The second is an adjustment to offset extreme  
5 load changes that have severely and adversely affected a customer’s load factor. The 2026  
6 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.D, include the calculations for  
7 applying these adjustments, applicable qualifying criteria, and notice requirements. *See*  
8 Section 5.4.3 below (providing more information regarding this adjustment).

#### 9 10 **4.1.1.3 Tier 1 Load Shaping Charge**

##### 11 **4.1.1.3.1 Load Shaping Charge Rates**

12 The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—  
13 for each of 12 months). The Load Shaping rates are set equal to the rate period average  
14 marginal cost of power for each monthly/diurnal period as determined in the Power  
15 Market Price Study and Documentation, BP-26-FS-BPA-04, § 2.4. *See* Power Rates Study  
16 Documentation, BP-26-FS-BPA-01A, Table 4.2. *See* Section 5.4.4 below (providing  
17 information on the Load Shaping Charge True-Up Adjustment).

##### 18 19 **4.1.1.3.2 Load Shaping Charge Billing Determinant**

20 The Billing Determinant for the Load Shaping charge is the difference between 1) a  
21 customer’s actual load served at Tier 1 rates and 2) the System Shaped Load, which is the  
22 customer’s annual load reshaped into the monthly/diurnal shape of RHWMTier 1 System  
23 Capability. The Load Shaping Billing Determinant can have either a positive or a negative  
24 value. Pursuant to the TRM, a Load Following customer’s Above-RHWMTier 1 Load that is  
25 forecast to be less than 8,760 MWh and is not served with non-federal resources will be

1 served by BPA at the Load Shaping rate and is reflected in this Billing Determinant. *See*  
2 TRM, BP-12-A-03, § 4.3.

3  
4 A customer's System Shaped Load is calculated as the RHWMTier 1 System Capability  
5 (*see* Section 1.4.2) for each of the 24 monthly/diurnal periods of the fiscal year multiplied  
6 by the customer's Non-Slice TOCA. The Load Shaping Billing Determinants are calculated  
7 as the amount of a customer's actual monthly/diurnal load (measured in kilowatts) to be  
8 served at Tier 1 rates minus the customer's System Shaped Load for the same  
9 monthly/diurnal period.

#### 10 11 **4.1.1.3.3 Monthly/Diurnal RHWMTier 1 System Capability**

12 The TRM prescribes that the monthly/diurnal shape of the RHWMTier 1 System Capability  
13 will be used to compute the System Shaped Load for purposes of computing Load Shaping  
14 Billing Determinants. The System Shaped Load is not updated if the RHWMTier 1 System  
15 Capability that was determined in the RHWMTier 1 System Capability is updated in the rate proceeding.  
16 The system shape is computed to be constant across both years of the rate period and is the  
17 average of each year's respective monthly/diurnal megawatthour amount. In a rate period  
18 that does not include a leap year, there will be 24 monthly/diurnal amounts for the RHWMTier  
19 Tier 1 System Capability specified in the GRSPs. In a rate period that includes a leap year,  
20 there will be 26 amounts, with a unique value for each February to account for the  
21 additional day. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP IIA.

#### 22 23 **4.1.2 PFp Tier 2 Charges**

24 Tier 2 charges (rates and billing determinants) apply to PF power purchased to meet a  
25 customer's Above-RHWMTier 1 System Capability Load. Tier 2 charges include:

- 26 • Load Shaping Charge

- Short-Term Charge
- Load Growth Charge

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.2.

#### **4.1.2.1 Tier 2 Load Shaping Charge**

Pursuant to the TRM, a Load Following customer's Above-RHWM Load that is forecast to be less than 8,760 MWh and that is not served with non-federal resources will be served at Tier 2 rates set equal to the Load Shaping rate. For ease of ratemaking and billing, and since it would create no material difference because the rate for the two is the same, BPA does not separate the Tier 2 Load Shaping Billing Determinant from the Tier 1 Load Shaping Billing Determinant. Rather, the Tier 1 Load Shaping Billing Determinant can include power purchased at Tier 1 and Tier 2 rates. See Section 4.1.1.3 above.

#### **4.1.2.2 Tier 2 Short-Term and Load Growth Charges**

With the exception of the Tier 2 Load Shaping Charge, Tier 2 rates are calculated in a module of RAM2026 and are summarized in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.5.1 and 3.5.2. Each rate is calculated by dividing the annual costs allocated to the specific Tier 2 cost pool (see Section 3.2.2 above) by the billing determinants (based on the annual average megawatt load obligations, excluding real power losses, for each Tier 2 rate alternative) in that same fiscal year. Each Tier 2 rate is established to recover all of the allocated costs associated with the product. The Tier 2 rates may be adjusted under certain circumstances, as shown in PF-26, Section 7.

The Tier 2 Billing Determinant is equal to each customer's commitment to purchase from BPA all or a portion of the customer's Above-RHWM Load. Each customer's Tier 2 rate

1 service amount is contractually established for FY 2026-2028. The totals for all customers  
2 are summarized in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.3.

#### 4 **4.1.3 PFp Melded Rates (Non-Tiered Rate)**

5 The PF Melded rate is a non-tiered rate applicable to the sale of Firm Requirements Power  
6 under contracts other than CHWM contracts. No sales under the PF Melded rate are  
7 forecast during the rate period, FY 2026-2028.

8  
9 Melded PF Public rates are included in Section 3 of the PF rate schedule and consist of  
10 12 HLH energy rates, 12 LLH energy rates, and 12 demand rates. The PFp melded energy  
11 rates are equal to the PFp Load Shaping rates less a scalar. The scalar is a single mills per  
12 kilowatthour value that adjusts the Load Shaping rates so that the PFp melded energy  
13 rates, in conjunction with the demand revenue, do not collect more or less revenue than the  
14 Tier 1 and Tier 2 revenue requirement allocated to the PFp loads. Calculation of the PFp  
15 melded energy rate components, including the scalar, is shown in Power Rates Study  
16 Documentation, BP-26-FS-BPA-01A, Table 3.1.8.2. The applicable demand rates are equal  
17 to the PFp Tier 1 demand rates.

18  
19 The PFp melded energy rates are subject to risk adjustments during the rate period  
20 pursuant to the Power CRAC; the Power RDC; and the Power FRP Surcharge. *See*  
21 Section 5.2 below. Any adjustments to rates and GRSPs during the rate period due to such  
22 risk adjustments will be summarized in Appendix A of the Power Rate Schedules and  
23 GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 3.

1 **4.1.4 Unanticipated Load Service Charge**

2 BPA provides Unanticipated Load Service (ULS) for Load Following customers under the  
3 PF rate schedule and provides a similar service under the NR and FPS rates. ULS is  
4 described in Section 5.10 below and in the 2026 Power Rate Schedules and GRSPs, BP-26-  
5 A-01-AP01, GRSP II.M.

6  
7 **4.1.5 PFp Resource Support Services Rates**

8 BPA offers RSS and related services for customers' variable, non-dispatchable non-federal  
9 resources in accordance with the CHWM contract. In general, RSS are designed to  
10 financially convert these resources into a flat annual block of power or the specified  
11 monthly/diurnal resource shape found in Exhibit A of the customer's CHWM contract.  
12 RSS available under the PFp rate schedule include the following:

- 13 • DFS, as discussed in Section 5.6.1.1 below and the 2026 Power Rate Schedules and  
14 GRSPs, BP-26-A-01-AP01, GRSP II.I.1.
- 15 • Grandfathered Generation Management Service, as discussed in Section 5.6.1.7  
16 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01,  
17 GRSP II.I.6.
- 18 • Resource Shaping Charge, as discussed in Sections 5.6.1.2-3 below and the 2026  
19 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.2.
- 20 • Secondary Crediting Service (SCS), as discussed in Section 5.6.1.6 below and the  
21 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.3.

22  
23 The related services include Transmission Scheduling Service, Transmission Curtailment  
24 Management Service, and RRS. These related services are provided under the FPS rate  
25 schedule and are discussed in Section 4.4 below.

1 **4.1.6 Priority Firm Exchange (PFx) Rate**

2 A utility-specific PFX rate applies to each participant in the REP for sales and purchases of  
3 exchange energy pursuant to an RPSA (for eligible consumer-owned utilities) or a REPSIA  
4 (for eligible investor-owned utilities).

5  
6 The 2012 REP Settlement (*see* Section 5.12) requires that BPA pay a fixed sum of REP  
7 benefits to IOUs eligible for the REP pursuant to a schedule of payments set forth in the  
8 2012 REP Settlement. 2012 REP Settlement, REP-12-A-02A. The yearly fixed sum is  
9 included in BPA's revenue requirement and collected in BPA's rates. Each IOU's share of  
10 the fixed amount of REP benefits is determined pursuant to the calculations contained in  
11 Section 6 of the 2012 REP Settlement. In particular, Section 6.2 of the 2012 REP Settlement  
12 describes a series of adjustments BPA is required to make to certain IOUs' shares of the  
13 REP benefits. BPA's implementation of Section 6.2, including the specific calculations BPA  
14 used to reach the resulting REP allocations, is shown in Power Rates Study Documentation,  
15 BP-26-FS-BPA-01A, Table 2.4.12.

16  
17 The PFX rate has two components: 1) two common Base PFX rates (one for COUs with  
18 CHWM contracts and another for all other REP participants); and 2) utility-specific REP  
19 Surcharges. The COUs have a different Base PFX rate because the PFp rate is tiered.  
20 Neither component of the PFX rate is diurnally differentiated or contains an additional  
21 charge for demand. Each participant's ASC is a single mills per kilowatthour rate applied to  
22 all kilowatthours. Likewise, the rate design for each participant's PFX rate is a single mills  
23 per kilowatthour rate applied to all kilowatthours.

24  
25 Base PFX rates are based on the average PF rate immediately prior to the determination of  
26 Section 7(b)(2) rate protection. The PFX rate applicable to IOUs (and any eligible COU  
27 without a CHWM contract) is computed by dividing all costs allocated to the PF rate pool by

1 all PF rate pool loads and then adding a transmission charge for delivering the exchange  
2 power to the customer. The PFx rate applicable to COUs with CHWM contracts is calculated  
3 in the same manner, except that the costs allocated to Tier 2 cost pools are excluded from  
4 the numerator and loads served at Tier 2 rates are excluded from the denominator.

5  
6 Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of  
7 providing 7(b)(2) rate protection continues to be assessed. *See* 2012 REP Settlement,  
8 REP-12-A-02A; Section 2.2.2.3 above. The amount of 7(b)(2) rate protection costs  
9 allocated to the PFx rates is allocated to each IOU REP participant on a pro-rata basis using  
10 REP Unconstrained Benefits calculated from the difference between utility-specific ASCs  
11 and the Base PFx rate for IOUs as the allocator. The cost of 7(b)(2) protection recovered  
12 from the 7(b)(3) Surcharge applied to the PFx rate for exchanging COUs is imputed from  
13 the aggregate protection allocated to IOUs relative to the aggregate Unconstrained Benefits  
14 among the IOUs, so that exchanging COUs bear an equitable responsibility for 7(b)(2) rate  
15 protection owed to the PFp rate pool. The total amount allocated to each REP participant is  
16 divided by the participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

17  
18 For each REP participant, the applicable Base PFx rate is added to its utility-specific 7(b)(3)  
19 surcharge to determine its utility-specific PFx rate. For each month of the rate period, the  
20 participant will submit its exchange load to BPA for the prior month. Under either RPSA or  
21 REPSIA, a utility-specific PFx rate is applied to BPA's sales of exchange energy and the  
22 participating utility's ASC is applied to BPA's purchase of exchange energy, where the  
23 exchange energy is equal to the utility's eligible residential and farm load. The difference  
24 between the amount BPA pays for exchange "purchases" and the amount BPA receives for  
25 exchange "sales" determines the amount of monetary REP benefits BPA pays the utility.  
26 BPA will multiply this invoiced exchange load by the difference between the participant's

1 ASC and its PFx rate to calculate the amount of REP benefits payable to the participant.

2 *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.11.

## 4 **4.2 New Resource Firm Power (NR-26) Rate**

5 The NR-26 rate applies to sales to investor-owned utilities under Northwest Power Act  
6 Section 5(b) requirements contracts. 16 U.S.C. § 839c(b). The NR-26 rate is also applicable  
7 to sales to any public body, cooperative, or federal agency to the extent such power is used  
8 to serve any NLSL, as defined by the Northwest Power Act, including planned NLSLs, as  
9 defined in Exhibit D of a customer's CHWM contract. The NR-26 rate includes energy and  
10 demand rates.

### 12 **4.2.1 NR Energy Charge**

13 Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and  
14 LLH differentiation of the PFp Load Shaping rates. *See* Power Rates Study Documentation,  
15 BP-26-FS-BPA-01A, Table 3.1.8.4. The NR energy rates are determined by adjusting each  
16 PFp Load Shaping rate by an equal scalar until the NR energy rates recover the allocated  
17 NR revenue requirement minus the forecast NR Demand Charge revenue. *Id.*

18  
19 After the scaling process is complete, an REP Surcharge is added to each of the  
20 monthly/diurnal energy rates. Section 7(b)(3) of the Northwest Power Act provides that  
21 the cost of 7(b)(2) rate protection afforded to preference customers is allocated to all other  
22 power sold, which includes power sold at the NR rate. 16 U.S.C. § 839e(b)(2)-(3); *see*  
23 Section 2.2.2.4 above. The cost of rate protection allocated to the NR rate is determined  
24 pursuant to the 2012 REP Settlement. Refer to Power Rates Study Documentation, BP-26-  
25 FS-BPA-01A, Table 2.4.14, for the calculation of the REP Surcharge.

1 A customer's billing determinant for the NR Energy charge is the total of the customer's  
2 NR hourly loads for each diurnal period.

3  
4 The NR Energy rates are subject to risk adjustments during the rate period pursuant to the  
5 Power CRAC, the Power RDC, and the Power FRP Surcharge. *See* Section 5.2 below. Any  
6 adjustments to rates and GRSPs during the rate period due to such risk adjustments will be  
7 summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate  
8 Schedules and GRSPs, BP-26-A-01-AP01, NR-26, § 2.1.1.2.

#### 9 10 **4.2.2 NR Demand Charge**

11 The demand rates for the NR rate schedule are equal to the PFp demand rates described in  
12 Section 4.1.1.2 above. As with the PFp Demand Charge, the NR Demand Billing  
13 Determinant is only a portion of the peak demand placed on BPA. The NR Demand Billing  
14 Determinant is equal to the highest NR hourly load during HLH minus the average hourly  
15 HLH energy purchased in that particular month at the NR energy rates.

#### 16 17 **4.2.3 Unanticipated Load Service Charge**

18 ULS is available under the NR-26 rate schedule for NLSLs and requirements service  
19 requested by IOUs. *See* Section 5.10 below and the 2026 Power Rate Schedules and GRSPs,  
20 BP-26-A-01-AP01, GRSP II.M, for details.

#### 21 22 **4.2.4 NR Services**

23 NR Services for NLSLs are applicable to Load Following customers serving NLSLs with  
24 non-federal resources. NR Energy Shaping Service is discussed in Section 5.6.2.1 below and  
25 specified in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.J.1.

### 4.3 Industrial Firm Power (IP-26) Rate

The IP-26 rate schedule is available for firm power sales to DSIs pursuant to Section 5(d) of the Northwest Power Act. 16 U.S.C. § 839c(d). The IP-26 rate includes energy and demand rates. DSIs purchasing power pursuant to the IP-26 rate schedule are required to provide the Minimum DSI Operating Reserve–Supplemental.

#### 4.3.1 IP Energy Charge

##### 4.3.1.1 IP Energy Rates

The IP rate design includes 24 monthly/diurnal energy rates, two for each month, and one each for HLH and LLH. The IP energy rates are shaped using the PFp Melded rates. *See* Section 4.1.3 above.

As described below, IP Energy rates are calculated by adjusting the PFp melded rates by the VOR Credit for operating reserves provided by the DSI load, the typical industrial margin, and an REP Surcharge. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.3.

The IP energy rates are subject to risk adjustments during the rate period pursuant to the Power CRAC; the Power RDC; and the Power FRP Surcharge. *See* Section 5.2 below. Any adjustments to rates and GRSPs during the rate period due to such risk adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, IP-26, § 2.1.1.3.

##### 4.3.1.1.1 IP Adjustment for Value of Reserves Provided

A VOR Credit is included in the IP rate, as provided in Section 7(c)(3) of the Northwest Power Act. 16 U.S.C. § 839e(c)(3); *see* Section 2.2.2.5.2 above. The forecast DSI load

1 amount is shown in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 2.4. Based  
2 on provisions of DSI contracts currently in place, these power sales are assumed to provide  
3 interruption reserve rights (operating reserves) to BPA, and therefore the IP rate includes  
4 a VOR Credit.

5  
6 The first step for valuing operating reserves provided by DSIs is to determine a marginal  
7 price for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve  
8 obligations, the cost of Operating Reserves-Supplemental service is used to establish the  
9 marginal value.

10  
11 The second step in valuing the DSI reserves is to determine the quantity of reserves  
12 provided. To calculate this quantity, the total DSI load is reduced to account for wheel-  
13 turning load that cannot be curtailed. The wheel-turning load is forecast to be 0 aMW.  
14 The interruption reserves provided are 10 percent of the remaining DSI load (11 MW),  
15 or 1.1 MW.

16  
17 The VOR Credit included in the IP-26 rate is 0.675 mills/kWh. See Power Rates Study  
18 Documentation, BP-26-FS-BPA-01A, Table 2.4.1, for calculation of the value of DSI reserves.

#### 19 20 **4.3.1.1.2 IP Rate Typical Margin**

21 Another component of the IP rate is the typical margin, as provided in Section 7(c)(2) of the  
22 Northwest Power Act. 16 U.S.C. § 839e(c)(2); see Section 2.2.2.5.2 above. The typical  
23 margin is based generally on the overhead costs that COUs add to the cost of power in  
24 setting their retail industrial rates. The typical margin included in the IP-26 rate is  
25 0.966 mills/kWh. The typical margin is calculated in Appendix A.

1 **4.3.1.1.3 REP Surcharge**

2 The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest  
3 Power Act provides that the cost of 7(b)(2) rate protection afforded to preference  
4 customers must be allocated to all other power sold, which includes power sold at the  
5 IP rate. 16 U.S.C. §§ 839e(b)(2)-(3); *see* Section 2.2.2.3 above. The cost of rate protection  
6 allocated to the IP rate is determined pursuant to the 2012 REP Settlement and is included  
7 in the IP-26 rate. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.14,  
8 for calculation of the REP Surcharge.

9  
10 **4.3.1.2 IP Energy Charge Billing Determinant**

11 The customer-specific Energy Billing Determinant is the Energy Entitlement specified in  
12 the customer's contract.

13  
14 **4.3.2 IP Demand Charge**

15 The demand rates for the IP rate schedule are equal to the PFp demand rates described in  
16 Section 4.1.1.2 above. As with the PFp demand charge, the IP Demand Billing Determinant  
17 is applied to only a portion of the DSI peak demand placed on BPA. The IP Demand Billing  
18 Determinant in each billing month is equal to a DSI's highest HLH schedule, or metered  
19 amount, minus the average HLH schedule amount, or metered amount, less any applicable  
20 Industrial Demand Adjuster. The Industrial Demand Adjuster is a monthly demand  
21 (expressed in kilowatts) that is subtracted from the hourly peak schedule amount when  
22 calculating the IP Demand Billing Determinant. *See* 2026 Power Rate Schedules and GRSPs,  
23 BP-26-A-01-AP01, IP-26, § 2.2.2.

24  
25 **4.4 Firm Power and Surplus Products and Services (FPS-26) Rate**

26 Products and services available under the FPS rate schedule are listed in the next  
27 paragraph and described in the FPS-26 rate schedule. Sales under this rate schedule are

1 discretionary; BPA is not obligated to sell any of these products, even if such sales will not  
2 displace PF, NR, or IP sales. Products priced under the FPS-26 rate schedule may be sold at  
3 market-based or negotiated rates, which may have a demand component, an energy  
4 component, or both. Rates and billing determinants for the products and services sold  
5 under the FPS rate schedule are either specified by BPA or mutually agreed upon by BPA  
6 and the customer. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, FPS-26.*  
7

#### 8 **4.4.1 FPS Charges**

9 When available for use within and outside the Pacific Northwest, the FPS-26 rate schedule  
10 has nine categories of products and services:

- 11 1. Firm power (capacity and/or energy), including secondary energy or firm  
12 capacity.
- 13 2. Capacity without energy: stand-alone capacity products.
- 14 3. Energy shaping services.
- 15 4. Reservations and rights to change services: reservations of power and  
16 services, when available, and the rights to change sales and services.
- 17 5. Reassignment or remarketing of surplus transmission capacity: Power  
18 Services may reassign or remarket its surplus transmission capacity that has  
19 been purchased from a transmission provider, including BPA's Transmission  
20 Services, consistent with the terms of the transmission provider's Open  
21 Access Transmission Tariff.
- 22 6. Other capacity, energy, and power scheduling products and services, as  
23 available.
- 24 7. Services for non-federal resources:
  - 25 a. Transmission Scheduling Service and Transmission Curtailment  
26 Management Service, Section 5.6.1.5 below and 2026 Power Rate

1 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.5.

2 b. Forced Outage Reserve Service, Section 5.6.1.4 below and 2026 Power  
3 Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.4.

4 c. Resource Remarketing Service, § 5.6.1.8 below and 2026 Power Rate  
5 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.7.

6 8. Unanticipated Load Service, Section 5.10 below and 2026 Power Rate  
7 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M.4.

8 9. Real Power Losses: Power Services may sell power to BPA Transmission  
9 customers for Real Power Loss returns as defined by BPA Transmission  
10 Services.

11 *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, FPS-26.*

#### 13 **4.4.2 FPS Real Power Losses Service**

14 When power is sent across a transmission system a portion of the power transmitted is  
15 lost. Customers have a choice to physically provide that lost power (in-kind loss returns or  
16 using Slice Output), meaning provide additional power to cover the loss, or to purchase  
17 power equal to the lost amount from BPA (FPS real power loss returns). This section  
18 describes the methodology used to calculate the cost of real power loss returns when a  
19 customer chooses to purchase the lost power from Power Services.

##### 21 **4.4.2.1 Energy Cost of Providing Real Power Losses**

22 The energy cost of providing real power losses will be based on actual hourly market prices  
23 from the hour the loss obligation occurred. The market prices will be the greater of 0 and  
24 the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market  
25 Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss

1 occurred. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to  
2 the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

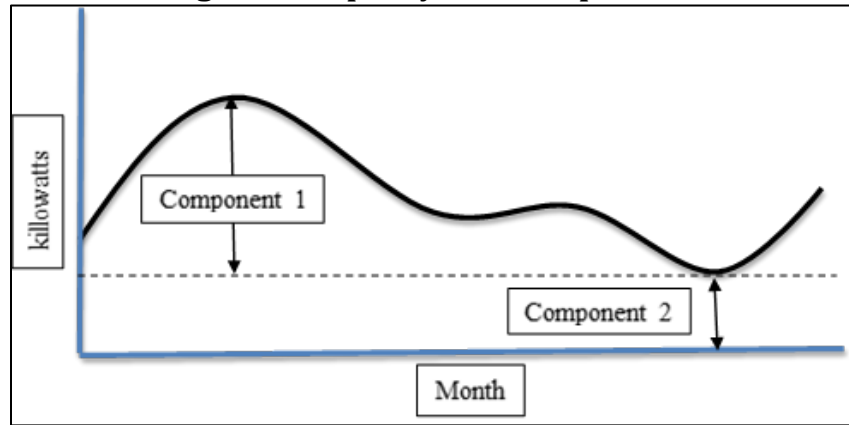
#### 3 4 **4.4.2.2 Capacity Cost of Providing Real Power Losses**

5 The methodology used to establish the cost for the FPS Real Power Losses Service uses  
6 three historical years (FY 2019, FY 2020, and FY 2021) of losses data to calculate the  
7 capacity cost to BPA had all customers with loss obligations during these historical years  
8 chose to purchase those losses from Power Services. That total capacity cost is divided by  
9 the average annual amount of lost energy (kilowatthours) included in that same data set to  
10 calculate a volumetric capacity rate in mills per kilowatthour that is applied to losses  
11 purchased through Power Services FPS rate schedule.

12  
13 Two capacity cost components are quantified and summed to calculate the total capacity  
14 cost. The first component captures the cost of the capacity needed to flex between the  
15 minimum energy provided and the max energy provided in a month. The second  
16 component captures the cost of the capacity (or premium) typically included when a block  
17 of power is purchased well in advance of the operating hour. Together, these two  
18 components capture the entire stack of capacity (zero to maximum amount) needed to  
19 serve the load requirement of those three years of transmission loss data (see Figure 2  
20 below).

1

**Figure 2. Capacity Cost Components**



2

### 3 **Capacity Cost Component 1:**

4 Capacity cost component 1 is calculated by multiplying the average monthly quantity of  
 5 incremental (*inc*) capacity provided for a year (using FY 2019, FY 2020, and FY 2021) by  
 6 the unit cost of Supplemental Operating Reserve capacity as documented in Section 9.3.1  
 7 below. The average monthly quantity of *inc* capacity is calculated by taking the average  
 8 maximum hourly amount by month in kilowatts (*i.e.*, for the month of March, the  
 9 calculation would be the average of the maximum hourly March 2019, maximum hourly  
 10 March 2020, and maximum hourly March 2021) minus the average minimum hourly  
 11 amount of energy for the same month (*i.e.*, for the month of March, the calculation would be  
 12 the average of the minimum hourly March 2019, minimum hourly March 2020, and  
 13 minimum hourly March 2021). The net of these two values is calculated for all 12 months  
 14 of the year and summed to equal the quantity of *inc* capacity provided in capacity cost  
 15 component 1.

16

17

$$AveMaxMonth_i = \sum_{i=1}^{12} \frac{[HrMaxMonth_{i_{2019}} + HrMaxMonth_{i_{2020}} + HrMaxMonth_{i_{2021}}]}{3}$$

18

$$AveMinMonth_i = \sum_{i=1}^{12} \frac{[HrMinMonth_{i_{2019}} + HrMinMonth_{i_{2020}} + HrMinMonth_{i_{2021}}]}{3}$$

$$AnnualSumMonthlyCapacity_{inc} = \sum_{i=1}^{12} AveMaxMonth_i - AveMinMonth_i$$

$$CapacityCostComp_1 = AnnualSumMonthlyCapacity_{inc} \times UC_{sup}$$

Where:

*i* refers to a particular month in the fiscal year with 1 being October and 12 being September.

*HrMaxMonth<sub>i</sub><sub>2019</sub>* refers to the maximum hourly value in month *i* of fiscal year 2019.

*HrMaxMonth<sub>i</sub><sub>2020</sub>* refers to the maximum hourly value in month *i* of fiscal year 2020.

*HrMaxMonth<sub>i</sub><sub>2021</sub>* refers to the maximum hourly value in month *i* of fiscal year 2021.

*HrMinMonth<sub>i</sub><sub>2019</sub>* refers to the minimum hourly value in month *i* of fiscal year 2019.

*HrMinMonth<sub>i</sub><sub>2020</sub>* refers to the minimum hourly value in month *i* of fiscal year 2020.

*HrMinMonth<sub>i</sub><sub>2021</sub>* refers to the minimum hourly value in month *i* of fiscal year 2021.

*UC<sub>sup</sub>* refers to the unit cost for Supplemental Operating reserves.

*CapacityCostComp<sub>1</sub>* refers to the total annual cost of capacity cost component one.

**Capacity Cost Component 2:**

Capacity cost component 2 is calculated in two steps. Step one is to multiply the average minimum amount of power provided for each month of the year (*i.e.*, for the month of March, the calculation would be the average of the minimum hourly March 2019, minimum hourly March 2020, and minimum hourly March 2021) by the average amount of hours for that same month (*i.e.*, for the month of March, the calculation would be the average of the hours in March 2019, the hours in March 2020, and the hours in March 2021). Step two is to multiply the total amount of kilowatthours calculated in step one by 14.55 mills/kWh.

$$AveMinMonth_i = \sum_{i=1}^{12} \frac{[HrMinMonth_{i_{2019}} + HrMinMonth_{i_{2020}} + HrMinMonth_{i_{2021}}]}{3}$$

$$AveHrsMonth_i = \sum_{i=1}^{12} \frac{[HrsMonth_{i_{2019}} + HrsMonth_{i_{2020}} + HrsMonth_{i_{2021}}]}{3}$$

$$AveAnnualPower = AveMinMonth_i \times AveHrsMonth_i$$

$$CapacityCostComp_2 = AveAnnualPower \times 14.55 \text{ mill per kWh}$$

Where:

$i$  refers to a particular month in the fiscal year with 1 being October and 12 being September.

$HrMinMonth_{i_{2019}}$  refers to the maximum hourly value in month  $i$  of fiscal year 2019.

$HrMinMonth_{i_{2020}}$  refers to the maximum hourly value in month  $i$  of fiscal year 2020.

$HrMinMonth_{i_{2021}}$  refers to the maximum hourly value in month  $i$  of fiscal year 2021.

$HrsMonth_{i_{2019}}$  refers to the minimum hourly value in month  $i$  of fiscal year 2019.

$HrsMonth_{i_{2020}}$  refers to the minimum hourly value in month  $i$  of fiscal year 2020.

$HrsMonth_{i_{2021}}$  refers to the minimum hourly value in month  $i$  of fiscal year 2021.

$CapacityCostComp_2$  refers to the total annual cost of capacity cost component two.

Capacity cost component 1 and 2 are summed and divide by the average annual amount of kilowatt-hours from the same historical dataset to compute a volumetric dollars per kilowatthour capacity charge applied in addition to the energy charge for real power losses purchases from BPA. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.4.

1 **5. GENERAL RATE SCHEDULE PROVISIONS**

2  
3 The GRSPs describe the adjustments, charges, and special rate provisions applicable to  
4 BPA’s rate schedules. The GRSPs also define the power products and services BPA offers  
5 and other applicable terms. The GRSPs described in this section are presented in their  
6 entirety in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

7  
8 **5.1 RHWMTier 1 System Capability**

9 The Rate Period High Water Mark Tier 1 System Capability (RT1SC) is determined in the  
10 RHWMTier 1 Process outside the rate proceeding, as described in Section 1.4 above and the TRM,  
11 BP-12-A-03, § 4.2.1.

12  
13 As described in Section 4.1.1.3.2 above, BPA uses the monthly/diurnal shape of RT1SC and  
14 the resulting System Shaped Load in developing the Billing Determinant for the Load  
15 Shaping charge. The Billing Determinant for the Load Shaping charge is the difference  
16 between a customer’s actual load served at Tier 1 rates and the customer’s annual load  
17 used to calculate its TOCA reshaped into the monthly/diurnal shape of RT1SC. The  
18 monthly/diurnal RT1SC values for the FY 2026-2028 rate period are shown in the 2026  
19 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.A, Table A.

20  
21 **5.2 Risk Adjustments**

22 Power risk adjustment clauses will not be applicable to the portion of a customer’s service  
23 at PF Tier 1 rates that has been converted from a Slice product to a non-Slice product  
24 beginning October 1, 2025. However, the three risk adjustment clauses will apply to such  
25 customer’s entire service at PF Tier 1 rates for FY 2027 and FY 2028. See 2026 Power Rate  
26 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.O, II.P, and II.Q.

1 **5.2.1 Power Cost Recovery Adjustment Clause (Power CRAC)**

2 For each year of the rate period, the Power CRAC may result in an upward rate adjustment  
3 to respond to the financial circumstances BPA experiences before BPA can conduct a  
4 Section 7(i) rate proceeding to adjust its rates. If stated conditions are met, the CRAC will  
5 trigger, and a rate increase will go into effect for the period of December 1 through  
6 September 30 of the applicable year. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-*  
7 *01-AP01, GRSP II.O; Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2.*

8  
9 **5.2.2 Power Reserves Distribution Clause (Power RDC)**

10 For each year of the rate period, the Power RDC may result in deployment of Power  
11 financial reserves in order to further Power’s objectives. RDC funds may be used for debt  
12 reduction, incremental capital investment, rate reduction through a Power Dividend  
13 Distribution (Power DD), a distribution to customers, or any other Power-specific purposes  
14 determined by the Administrator. The RDC will trigger if 1) financial reserves attributed to  
15 Power exceed a defined threshold, and 2) BPA’s financial reserves exceed a defined  
16 threshold. If the RDC triggers, the Administrator will determine what part of the RDC  
17 Amount will be devoted to the Power objectives noted above. If reserves are allocated to a  
18 Power DD, the resulting rate decrease will go into effect for the month following the  
19 issuance of the Power RDC decision through September 30 of the applicable year.

20  
21 No cap on the Power RDC is included for the BP-26 rate period. *See 2026 Power Rate*  
22 *Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.P; Power and Transmission Risk Study,*  
23 *BP-26-FS-BPA-05, § 4.2.*

1 **5.2.3 Power FRP Surcharge**

2 For each year of the rate period, the Power FRP Surcharge may result in an upward  
3 adjustment to certain rates to increase financial reserves when reserves are below the  
4 lower threshold for Power. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05,  
5 § 4.2. If stated conditions are met, the Power FRP Surcharge will trigger, and a rate  
6 increase will go into effect for the period of December 1 through September 30 of the  
7 applicable year. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.Q.

8  
9 For FY 2026, FY 2027 and FY 2028, Power’s FRP Surcharge amount will be the lesser of  
10 \$40 million per year or the amount needed to fully recover financial reserves up to the  
11 lower financial reserves threshold for Power. *See* Power and Transmission Risk Study,  
12 BP-26-FS-BPA-05, Appendix A (FRP), § 4.2.2.

13  
14 **5.3 Slice True-Up Adjustment**

15 Slice customers pay their share of BPA’s actual costs. Therefore, Slice customers are  
16 subject to an annual Slice True-Up Adjustment for expenses, revenue credits, and  
17 adjustments allocated to the Composite cost pool and to the Slice cost pool. *See* § 7;  
18 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.

19  
20 **5.4 Discounts and Other Adjustments**

21 **5.4.1 Low Density Discount (LDD)**

22 Pursuant to Section 7(d)(1) of the Northwest Power Act, the LDD is a rate discount for  
23 customers with low system densities that meet the criteria specified in the 2026 Power  
24 Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.B. 16 U.S.C. § 839e(d)(1). As set  
25 forth in the TRM, LDD percentages are calculated to provide a discount on power  
26 purchased at Tier 1 rates that approximates the discount the customer would have

1 received under non-tiered rates. LDD credits for FY 2026, FY 2027 and FY 2028 are listed  
2 in Table 4, Line 9.

#### 3 4 **5.4.2 Irrigation Rate Discount (IRD)**

5 The IRD is a discount to the PFp Tier 1 rates for eligible irrigation load served by  
6 customers. An irrigation credit is available to customers with eligible irrigation load as set  
7 forth in Exhibit D of the customers' CHWM contracts. The amount of irrigation credit a  
8 customer will receive on its monthly bills during the irrigation season is based on the lesser  
9 of the customer's actual Tier 1 energy purchase and the eligible irrigation load amounts in  
10 the customer's CHWM contract. The discount will appear as a credit on customers' bills to  
11 offset Tier 1 charges for eligible irrigation loads. This discount is available to eligible loads  
12 during May, June, July, August, and September during the BP-26 rate period. *See* 2026  
13 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP I.I.C. IRD Credits for FY 2026,  
14 FY 2027 and FY 2028 are shown in Table 4, Line 8.

##### 15 16 **5.4.2.1 Irrigation Rate Discount True-Up and Reimbursement**

17 At the end of each irrigation season, each customer with eligible irrigation load will provide  
18 to BPA its measured May-through-September irrigation load amounts, which will be used  
19 to determine if a true-up and reimbursement to BPA is applicable. If BPA determines that  
20 the measured irrigation load amounts are less than the billed irrigation load amounts, then  
21 the purchaser must reimburse BPA for the excess IRD Credits. Excess IRD Credits are  
22 calculated as the IRD rate multiplied by the difference between the billed irrigation load  
23 and the measured irrigation load. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-  
24 AP01, GRSP I.I.C.3.

1 **5.4.2.2 Calculation of the Irrigation Rate Discount**

2 The TRM establishes the method for calculating the IRD. The process begins with a fixed  
3 Irrigation Rate Mitigation Program (IRMP) percentage of 37.06 percent. *See* TRM, BP-12-  
4 A-03, § 10.3; BP-12 Power Rates Study Documentation, BP-12-FS-BPA-01A, Table 3.12.

5  
6 The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads  
7 will pay through the Composite customer charge, Non-Slice customer charge, and Load  
8 Shaping charge, adjusted for any applicable LDD, divided by the sum of the irrigation loads  
9 (expressed in megawatthours) to derive a dollars-per-megawatthour discount. The  
10 applicable LDD is calculated as the weighted average LDD of eligible irrigation customers,  
11 weighted with eligible irrigation loads. *See* Power Rates Study Documentation, BP-26-FS-  
12 BPA-01A, Table 5.1 for the calculation of the applicable LDD.

13  
14 Forecast revenue for irrigation loads is calculated using an IRD TOCA derived by dividing  
15 the sum of the irrigation loads (expressed in average megawatts) by the sum of all RHWMs.  
16 The IRD TOCA is applied consistent with TRM Section 5 for calculation of forecast irrigation  
17 revenues from the Composite customer charge, Non-Slice customer charge, and Load  
18 Shaping charge. The calculation is shown in Power Rates Study Documentation, BP-26-FS-  
19 BPA-01A, Table 2.3.3.1.

20  
21 **5.4.3 Demand Rate Billing Determinant Adjustment**

22 As described in GRSP II.D, in two limited circumstances BPA may reduce an unusually high  
23 Demand Charge Billing Determinant and provide some demand billing relief to a customer.  
24 *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.D.

1 First, when a customer’s loads differ significantly from one part of the month to another,  
2 the customer may experience overall low average HLH energy use, relatively high customer  
3 system peak, and a resulting high Demand Billing Determinant. In this situation, BPA may  
4 adjust the Demand Billing Determinant by calculating partial-month billing determinants  
5 and use the higher of the two (or more) partial-month billing determinants for the entire  
6 billing month. Example loads include large industrial or irrigation loads that occur during  
7 only a part of a month.

8  
9 Second, when an Uncontrollable Force outage occurs on a customer’s system, the  
10 restoration of service may result in a spike in usage, called a recovery peak. BPA may  
11 reduce the customer’s system peak established by a recovery peak to the next highest peak  
12 of the month and thereby reduce that month’s billing determinant.

#### 14 **5.4.4 Load Shaping Charge True-Up Adjustment**

15 As noted in TRM Section 5.2.4, at the end of each fiscal year BPA will calculate the Load  
16 Shaping Charge True-Up for each Load Following customer. The purpose of the true-up is  
17 to avoid charging or crediting the market-based Load Shaping rate for energy within the  
18 customer’s RHWM rather than charging or crediting the cost-based Tier 1 rate for that  
19 energy. BPA applies the true-up when a Load Following customer’s TOCA Load or Actual  
20 Annual Tier 1 Load is less than its RHWM. The LSTUR is the difference between 1) the  
21 Non-Slice load-weighted average of the Load Shaping rates, and 2) the Composite Customer  
22 rate plus the Non-Slice Customer rate, converted to mills per kilowatthour. The process for  
23 calculating the Load Shaping True-Up Adjustment is shown in TRM, BP-12-A-03,  
24 Section 5.2.4, Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.5, and the  
25 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP I.I.E.

1 **5.4.5 Special Implementation Provision for Load Shaping True-Up**

2 The Load Shaping True-Up Adjustment includes a special implementation provision that  
3 applies if two conditions are met: 1) a customer has Above-RHWM Load, and 2) the  
4 customer has unused RHWM. If these conditions are met, the customer may be eligible for  
5 a Load Shaping True-Up Credit in addition to the one described above. The amount of the  
6 additional Load Shaping True-Up Credit depends on a second calculation. *See 2026 Power*  
7 *Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.E.3.*

8  
9 The special implementation provision was originally designed to solve a transitional  
10 implementation issue caused by setting Above-RHWM Load based on a forecast different  
11 from the one used to determine a customer’s TOCA. This provision also has a longer term  
12 application, because Above-RHWM Load is determined in the RHWM Process (prior to the  
13 Initial Proposal of each rate proceeding). A Load Following customer’s TOCA can be  
14 updated prior to each fiscal year, or within a fiscal year, if there is substantial reason for  
15 BPA to believe the customer’s Actual Annual Tier 1 Load will be different than the forecast  
16 Tier 1 Load determined in the RHWM Process or the applicable year. *See 2026 Power Rate*  
17 *Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.1.* A consequence of using forecasts  
18 prepared at different times is the possibility that a customer could have both Above-RHWM  
19 Load and unused RHWM.

20  
21 **5.4.6 Tier 2 Rate Transmission Curtailment Management Service Adjustment**

22 The Tier 2 rate schedule includes an adjustment for TCMS-related costs. This adjustment  
23 will recover the cost BPA incurs as a result of a transmission event—either a planned  
24 transmission outage or a transmission curtailment. The event would occur along the  
25 transmission path used to deliver energy associated with power purchases for the Tier 2  
26 cost pools; that is, it would occur between the Point of Receipt (POR) and the Point of

1 Delivery (POD). The adjustment is described in the 2026 Power Rate Schedules and GRSPs,  
2 BP-26-A-01-AP01, GRSP II.F.

#### 4 **5.4.7 TOCA Adjustment**

5 For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA  
6 for each year of the rate period is calculated in the BP-26 7(i) process. A Load Following  
7 customer's TOCA for a fiscal year may be adjusted 1) to account for a significant change in  
8 the customer's total load, and 2) within a fiscal year due to a change to the customer's  
9 Existing Resource amounts within the same fiscal year, as detailed in the 2026 Power Rate  
10 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.1. A Slice/Block or Block customer's  
11 TOCA may be adjusted 1) for a fiscal year as part of the CHWM contract annual Net  
12 Requirement process, and 2) within a fiscal year due to a change to the customer's  
13 Specified Resource amounts within the same fiscal year, as detailed in the 2026 Power Rate  
14 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.2. Additionally, a customer's TOCA may  
15 be modified for a fiscal year or within a fiscal year if the customer's CHWM and associated  
16 RHWM have changed due to load annexations between customers with CHWM contracts.

#### 18 **5.4.8 DSI Reserves Adjustment**

19 In the event BPA agrees to acquire an additional reserve product from a DSI, this provision  
20 1) establishes the mechanism through which BPA compensates the DSI, and 2) places a cap  
21 on the unit price of any supplemental operating reserve product to be purchased to ensure  
22 that the reserve acquisition is cost-effective. *See* 2026 Power Rate Schedules and GRSPs,  
23 BP-26-A-01-AP01, GRSP II.H.

1 **5.5 Conservation Surcharge**

2 Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge  
3 recommended by the NPCC pursuant to Section 4(f)(2) of the Act. 16 U.S.C. §§ 839e(h),  
4 839b(f)(2). BPA does not currently anticipate applying such a surcharge in the FY 2026-  
5 2028 rate period. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.U.*

6  
7 **5.6 Resource Support Services and Related Services**

8 BPA offers services to support resources under the PF, NR, and FPS rate schedules. These  
9 services are designed to support non-federal resources; however, there are situations for  
10 ratemaking purposes where these services are used to financially flatten federal resources.  
11 *See Section 3.2.3.1.4 above.* The RSS rates relevant to the PFp rate schedule include:

- 12 • Diurnal Flattening Service (DFS) Charges
- 13 • Resource Shaping Charge (RSC) and Resource Shaping Charge Adjustment
- 14 • Secondary Crediting Service (SCS) Charges
- 15 • Grandfathered Generation Management Service (GMS) Reservation Fee

16  
17 The RSS and related service rates relevant to the NR rate schedule for NLSLs include:

- 18 • NR Energy Shaping Service Charges (NR ESS)

19  
20 The RSS and related rates relevant to the FPS rate schedule include:

- 21 • Forced Outage Reserve Service (FORS) Charges
- 22 • Transmission Scheduling Service (TSS) Charges
- 23 • Transmission Curtailment Management Service (TCMS) Charges
- 24 • Resource Remarketing (RMS) Service Credits

1 Forecast revenue from RSS and related services is used to credit Tier 1 cost pools. *See*  
2 Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.2 and 3.7. For this rate  
3 period, three RSS model runs were conducted with data from FY 2026 and FY 2027,  
4 FY 2027 and FY 2028, and FY 2026 and FY 2028, and averaged together to calculate the  
5 RSS and related rates discussed in the following sections.

## 6 7 **5.6.1 Resource Support Services and Transmission Scheduling Service**

### 8 **5.6.1.1 Diurnal Flattening Service**

9 DFS is an optional service that financially converts the output of a variable, non-  
10 dispatchable non-federal resource to an equivalent flat amount of power within each  
11 diurnal period of a month. When DFS charges are coupled with RSC, the variable output of  
12 a generating resource is financially converted to a flat annual block of power. DFS applies  
13 to any non-federal resource the customer applies to its load and any portion of the  
14 resource remarketed by BPA.

15  
16 The RSS module of RAM2026 calculates a unique set of rates and charges for each resource  
17 to which DFS is applied. Included in Power Rates Study Documentation, BP-26-FS-  
18 BPA-01A, Table 3.11, are the final rates and charges calculated for customers that have  
19 requested DFS for their resources. PF-26 rate schedule Sections 5.1 and 5.2 describe the  
20 general rate application of the DFS-related charges. GRSP II.I includes DFS rates and RSC.  
21 *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

22  
23 DFS charges include the following elements:

- 24 • A DFS capacity charge based on the PFp Tier 1 demand rate applied to the difference  
25 between the calculated firm capacity of the resource and the planned average HLH

1 generation of the resource. This charge reflects the costs of reserving an amount of  
2 capacity to smooth the variable generation of a resource into a flat block of power.

- 3 • A DFS energy charge based on the potential cost of storing and releasing power  
4 using a resource capable of storing energy (pumped storage) to balance the hourly  
5 shape of the resource to which DFS is applied. This charge reflects the costs of  
6 energy storage to smooth the hourly generation variation into a flat  
7 monthly/diurnal block of power.

8  
9 When DFS is applied to a resource, the RSC and Adjustment must be added to the DFS  
10 charges to complete the financial conversion to a flat annual block of power. *See*  
11 *Sections 5.6.1.2-3 below.*

12  
13 Typically, the RSS module of RAM2026, which computes resource-specific RSS rates, will  
14 use scheduled amounts for resources that require e-Tags and meter amounts for “behind-  
15 the-meter” resources. However, for small resources or small shares of a resource, BPA may  
16 apply a meter amount instead of a schedule amount for purposes of pricing RSS if the meter  
17 amount produces lower RSS rates and charges.

#### 18 19 **5.6.1.1.1 DFS Energy Charge**

20 A unique DFS energy rate is developed for each resource to which DFS is applied. The  
21 purpose of this rate is to reflect the potential cost of storing and releasing energy to offset  
22 the hourly variability of the resource’s Exhibit D amounts. The DFS Energy Billing  
23 Determinant is the total actual generation. The DFS energy charge, GRSP II.I.1(a), is the  
24 product of multiplying the DFS energy rate by the DFS Energy Billing Determinant for each  
25 month. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. Power Rates*

1 Study Documentation, BP-26-FS-BPA-01A, Table 3.11 shows the DFS energy rates for the  
2 individual resources.

#### 3 4 **5.6.1.1.2 DFS Capacity Charge**

5 The DFS capacity charge is a fixed monthly amount calculated as noted in GRSP II.I.1(b)(3)  
6 and is based on the monthly PF Tier 1 demand rates, monthly planned amounts in  
7 Exhibit D, and the calculated monthly firm capacity of the resource. *See* 2026 Power Rate  
8 Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

9  
10 The RSS module of RAM2026 calculates the monthly firm capacity amounts for each  
11 resource. This calculation represents the lowest level of historical generation in an HLH  
12 period for each month after accounting for planned and forced outages. The firm capacity  
13 of a resource is the percentile of the forced outage rating calculated from the historical  
14 monthly HLH generation levels. For example, a resource with a 5 percent forced outage  
15 rating would have a firm capacity amount equal to the 5<sup>th</sup> percentile of the hourly historical  
16 generation amounts for the HLH period of a month.

17  
18 Each type of generating resource has a standard forced outage rating. This rating  
19 represents the average percentage of time that a generating resource is unavailable for  
20 load service due to unanticipated breakdown. BPA uses a minimum 5 percent forced  
21 outage rating for hydroelectric resources, 7 percent for thermal resources, and 10 percent  
22 for all other resources. Customers taking services that have charges including the use of a  
23 forced outage rating may request that BPA increase the forced outage rating for their  
24 resource, and those with a resource other than a hydroelectric resource may request that  
25 BPA decrease the forced outage rating to as low as 7 percent.

1 The monthly calculated HLH firm capacity of the resource also includes a planned outage  
2 adjustment. If the historical hourly data reflects an outage that was planned, the model  
3 does a second calculation of the monthly firm capacity amount. This test runs the same  
4 calculation as above but calculates the value approximately equal to the forced  
5 outage percentile of an hourly sample that does not include the hours that were identified  
6 as a planned outage. If the number of planned outage hours is less than 25 percent of the  
7 HLH in the month, no further adjustments are made to the value calculated by the planned  
8 outage calculation of firm capacity. If the number of planned outage hours is equal to  
9 25 percent or more of the HLH in the month but less than 75 percent of the hours in the  
10 month, the planned outage adjusted firm capacity value is reduced by multiplying it by one  
11 minus the percentage of planned outage hours in the month. If the number of planned  
12 outage hours in the month is equal to or greater than 75 percent of the HLH in the month,  
13 the firm capacity of the resource in that particular month is set to zero.

14  
15 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11 shows the individual  
16 DFS capacity charges that are calculated for the individual resources to which DFS is  
17 applied.

### 19 **5.6.1.2 Resource Shaping Charge**

20 The purpose of the RSC, GRSP II.I.2(a), is to reflect the value of buying and selling flat  
21 monthly/diurnal blocks of power in the market to convert a diurnally flat resource within  
22 the month into one that, on a planned basis, is flat across the year. *See 2026 Power Rate*  
23 *Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.* The Resource Shaping rates are set equal  
24 to the PFp Tier 1 Load Shaping rates, which represent a proxy market price. On a monthly  
25 basis the RSC can be a charge or a credit. The flat monthly RSCs are shown in Power Rates  
26 Study Documentation, BP-26-FS-BPA-01A, Table 3.11 for individual resources.

1 For Small, Non-Dispatchable Resources (as defined in the CHWM contract), the RSC will not  
2 apply. The actual generation amounts of these resources will be used in the calculation of  
3 the Actual Monthly/Diurnal Tier 1 Load when calculating the PFp Tier 1 Load Shaping  
4 charge and demand charge.

### 6 **5.6.1.3 Resource Shaping Charge Adjustment**

7 The purpose of the RSC Adjustment, GRSP II.I.2(b), is to capture the cost or value of the  
8 energy differences between the Exhibit D amounts and the actual generation of the  
9 resource. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.* This  
10 adjustment is a true-up of the RSC and completes the financial conversion to a flat annual  
11 block of power by making up for any energy cost differences between planned and actual  
12 generation amounts. The RSC Adjustment can result in either a charge or a credit.

### 14 **5.6.1.4 Forced Outage Reserve Service (FORS)**

15 FORS in GRSP II.I.4 is an optional service for BPA to provide an agreed-upon amount of  
16 capacity and energy to a customer with a qualifying resource that experiences a forced  
17 outage. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.* FORS is  
18 offered under the FPS rate schedule to customers with resources that meet requirements  
19 specified in the CHWM contract.

21 The charges for FORS are intended to reflect the cost of BPA 1) reserving capacity to back  
22 up a resource as insurance to cover a potential forced outage, and 2) providing  
23 replacement energy should a forced outage occur.

1 The FORS charges include the following elements:

- 2 • A FORS capacity charge based on the PFp Tier 1 demand rate, the calculated firm  
3 capacity of the resource for customers whose resource is also taking DFS, and the  
4 forced outage rating for the applicable resource. Power Rates Study Documentation,  
5 BP-26-FS-BPA-01A, Table 3.11, shows the FORS capacity charges calculated for each  
6 resource. The calculations regarding firm capacity and forced outage ratings are  
7 described above in Section 5.6.1.1.2. Additionally, the firm capacity amounts used to  
8 calculate the FORS capacity charges may be adjusted to account for planned outages  
9 if such planned outages are included in the DFS capacity charge.
- 10 • A FORS energy charge designed to pass through the cost of replacement energy that  
11 BPA provides during a customer's forced outage. The energy rate is based on a  
12 market price under two conditions and the amount of energy supplied during a  
13 forced outage event.

14  
15 Additionally, customers with FORS are limited to a maximum amount of energy provided  
16 during a fiscal year and a purchase period, as defined in the CHWM contracts. Such fiscal  
17 year and purchase period limits are calculated in the RSS module of RAM2026 and listed in  
18 Exhibit D of the customer's CHWM contract. The fiscal year limits are set equal to two  
19 times the product of the following: 1) the forced outage rating of the applicable resource,  
20 and 2) the sum of the monthly planned amounts in Exhibit D in megawatthours. The  
21 purchase period limits are set equal to the product of the following: 1) the forced outage  
22 rating of the applicable resource; 2) the annual average planned amounts in Exhibit D in  
23 megawatthours; and 3) the number of years in the purchase period.

1 **5.6.1.5 Transmission Scheduling Service (TSS) and Transmission Curtailment**  
2 **Management Service (TCMS)**

3 TSS is offered under the FPS rate schedule. It is a required service for customers with  
4 resources that meet eligibility requirements specified in the CHWM contract. TSS is a  
5 service provided by Power Services to undertake certain scheduling obligations on behalf  
6 of the customer. There are two available service levels of TSS: 1) full service (TSS-Full), in  
7 which BPA creates e-Tags for a customer's resources or Tier 2 purchases; and 2) partial  
8 service (TSS-Partial), in which a customer (or its scheduling agent) creates e-Tags for its  
9 non-federal resources and carbon copies Power Services on each tag. TCMS is an optional  
10 service related to TSS that is also offered under the FPS rate schedule for customers with  
11 resources that meet eligibility requirements specified in the CHWM contract. TCMS is a  
12 feature of TSS (both TSS-Full and TSS-Partial) under which BPA provides either  
13 replacement transmission or replacement energy to customers with qualifying resources  
14 that experience transmission events pursuant to the conditions specified in Exhibit F of the  
15 CHWM contract.

16  
17 If a Load Following customer is served by Transfer Service or is purchasing DFS or SCS  
18 services from BPA, it is required to have the TSS provisions added to its CHWM contract.  
19 However, only customers that have non-federal resources requiring e-Tags will be charged  
20 for TSS services. Customers that have one or multiple non-federal resource(s) requiring  
21 e-Tags may choose either TSS-Full or TSS-Partial for all of their non-federal resources that  
22 require e-Tags. Load Following customers that are not contractually required to take TSS  
23 can elect this optional service if they wish to have BPA produce the e-Tags for their  
24 resources. Without this service, the customer must supply replacement transmission or  
25 power when the resource's transmission path experiences an outage or curtailment. If it is

1 unable to do so, it may face an Unauthorized Increase charge. *See* 2026 Power Rate  
2 Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.N.

3  
4 Application of TSS to Tier 2 rates is described in Section 3.2.2.2 above. Application of the  
5 TCMS Adjustment to Tier 2 rates is described in Section 5.4.6 above.

#### 6 7 **5.6.1.5.1 TSS-Full Pricing Summary**

8 The charge for TSS-Full reflects the cost of scheduling a resource to its POD. A unique set of  
9 charges will be calculated for each resource to which TSS-Full is applied. The TSS-Full  
10 Charges, GRSP II.I.5(a), include the following elements:

- 11 • For resources requiring e-Tags, a monthly TSS charge based on the applicable  
12 resource's FY 2026-2028 Dedicated Resource amounts listed in Exhibit A of the  
13 Load Following CHWM contract.
- 14 • A TSS-Full rate that is based on the forecast operations scheduling cost for the rate  
15 period (including costs associated with power scheduling preschedule, real-time,  
16 and after-the-fact functions) divided by the total megawatthours of power BPA  
17 scheduled in FY 2021, FY 2022 and FY 2023. *See* Power Rates Study  
18 Documentation, BP-26-FS-BPA-01A, Table 3.4.
- 19 • An Annual Open Access Technology International, Inc. (OATI), registration fee,  
20 \$200 per customer, which is spread evenly across the customer's resources and  
21 billing periods.
- 22 • A transaction-based cap for the monthly TSS-Full charge (not including adjustments  
23 made to recover the cost of the OATI registration fee). *See* Section 5.6.1.5.2 below  
24 for details.

1 The RSS module of RAM2026 calculates a TSS-Full rate that is applied to each non-federal  
2 resource receiving service during the rate period. *See* Power Rates Study Documentation,  
3 BP-26-FS-BPA-01A, Table 3.11.

#### 5 **5.6.1.5.2 Transaction-Based Cap Applied to TSS-Full Charge**

6 The TSS-Full Charge, not including adjustments made to recover the cost of the OATI  
7 registration fee described above, is subject to a cap. For a Specified Resource or  
8 Unspecified Resource Amounts serving Above-RHWM Load, if the annual cost calculated  
9 using the TSS rate exceeds \$1,038 when divided by 12, then the monthly charge is capped  
10 at \$1,038/month. The cap is the result of multiplying 30 schedules per month (*e.g.*, one  
11 schedule per day on average) by the forecast operations scheduling cost for the rate period,  
12 divided by the total number of schedules Power Services produced in FY 2021, FY 2022,  
13 and FY 2023. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01,  
14 GRSP III.5(a)(3).

15  
16 For Unspecified Resource Amounts serving an NLSL or a 9(c) export decrement obligation,  
17 if the annual cost calculated using the TSS rate exceeds \$3,115 when divided by 12, then  
18 the monthly charge is capped at \$3,115/month. This cap follows the same methodology  
19 applied to Specified Resources and Unspecified Resource Amounts serving Above-RHWM  
20 Load but assumes three daily transactions. It is the result of multiplying 90 schedules per  
21 month (*e.g.*, three schedules per day on average) by the forecast operations scheduling cost  
22 for the rate period, divided by the total number of schedules Power Services produced in  
23 FY 2021, FY 2022, and FY 2023. *Id.*

1 **5.6.1.5.3 TSS-Partial Pricing Summary**

2 A customer with TSS-Partial takes on all scheduling and tagging functions for its non-  
3 federal resources and is required to carbon copy Power Services on each tag. TSS-Partial  
4 charges are based on the staffing time costs that are incurred by BPA when a customer fails  
5 to carbon copy BPA on an e-Tag or when BPA provides replacement power or transmission  
6 for a resource supported with TCMS. The TSS-Partial charges, GRSP II.I.5(b), include the  
7 following elements:

- 8 • A TSS-Partial rate of \$246 per TSS-Partial event, which is based on three hours of  
9 BPA Full-Time Employee (FTE) staffing time. An average BPA employee costs  
10 \$170,795 (including benefits) per year, or \$82.11 per hour.
- 11 • A TSS-Partial Billing Determinant, which is a count of TSS-Partial events that occur  
12 within a month. Each of the following is considered a single TSS-Partial event:  
13 1) a customer, or its scheduling agent, fails to carbon copy Power Services on a  
14 schedule, except if the power being scheduled was purchased from Power Services  
15 (including Slice output) and Power Services was included in the market path on the  
16 tag; or 2) a day that a customer has a TCMS charge.

17 *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.*

18  
19 **5.6.1.5.4 TCMS Pricing Summary**

20 The charge for TCMS reflects the cost of providing either replacement transmission or  
21 replacement energy when a transmission event occurs. TCMS is not available to support a  
22 resource to which TSS does not apply. The TCMS charges, GRSP II.I.5(c), include the  
23 following elements:

- 24 • A TCMS charge for the cost of replacement power that is based on: 1) the cost of  
25 replacement power if actually purchased by BPA; or 2) the LAP price for BPA as  
26 determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff when a distinct  
27 replacement power purchase was not made by BPA.

- A TCMS charge if alternative transmission is provided that is designed to pass through the cost to deliver the customer’s resource plus any additional costs, including real power losses, associated with using the replacement transmission.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

#### **5.6.1.6 Secondary Crediting Service (SCS)**

The PF-26 rate schedule includes SCS Charges, GRSP II.I.3, which provide a credit or charge to a Load Following customer that dedicates its entire share of the output of a hydroelectric Existing Resource to its load. See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. The customer will receive a credit for the energy produced by that resource in excess of the monthly/diurnal amounts specified in CHWM contract Exhibit A. The additional generation would increase BPA’s revenues because of the increased secondary energy BPA can market, or would lower BPA’s costs because of reduced balancing purchases. The customer will receive a charge for any energy shortfall by the resource from the monthly/diurnal Exhibit A amounts, because BPA’s secondary revenues would be lower or BPA’s balancing costs would be higher. If a customer does not take this service, it must apply the exact Exhibit A amounts to its load unless the resource is a small, non-dispatchable resource or qualifies for GMS.

The charges and credits for SCS are intended to reflect the cost or value of reshaping the customer’s resource into its Exhibit A amounts. The SCS Charges include the following elements:

- SCS Energy Charge or Credit, priced at the Resource Shaping rate. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11.
- An Administrative Charge based on the forced outage rating of the hydro resource, the PFp Tier 1 Demand rate, and the monthly HLH Exhibit A amounts.

1 GRSP II.I.3(a) includes the calculation for the SCS Shortfall Energy Charges and Secondary  
2 Energy Credits for the individual resources to which SCS is applied. *See* 2026 Power Rate  
3 Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

#### 4 5 **5.6.1.7 Grandfathered Generation Management Service (GMS) Reservation Fee**

6 The PF Tier 1 rate includes GMS, which allows a Load Following customer dedicating the  
7 entire output of an Existing Resource that received GMS during Subscription to run that  
8 resource against its load and offset its Tier 1 load and charges. The only charge specific to  
9 GMS is the GMS Reservation Fee, GRSP II.I.6, which is based on the forced outage rating of  
10 the applicable resource, the PFp Tier 1 Demand rate, and the resource's firm capacity. *See*  
11 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

#### 12 13 **5.6.1.8 Resource Remarketing Service**

14 RRS is available under the FPS rate schedule. It is a service that BPA may make available,  
15 at its discretion, to Load Following customers. Under RRS, BPA remarkets non-federal  
16 resources on behalf of customers and provides them with a remarketing credit net of  
17 possible remarketing fees for doing so. Further details on RRS are provided in  
18 Section 5.7.2.4 below.

### 19 20 **5.6.2 NR Services for New Large Single Loads**

#### 21 **5.6.2.1 NR Energy Shaping Service (NR ESS) for NLSL**

22 The NR-26 rate schedule includes NR ESS. NR ESS is required for Load Following  
23 customers serving NLSLs with non-federal resources. NR ESS is a service provided by BPA  
24 to shape the energy provided by customers to the energy needs of NLSLs. This service  
25 allows customers some flexibility in the accuracy of meeting the real-time energy needs of

1 NLSLs. This service includes a capacity component on a monthly basis, and an energy  
2 component settled on both an hourly and monthly basis.

3  
4 The capacity component, the NR ESS Capacity Charge, is based on the percentage level of  
5 service that a customer elects BPA to stand ready to provide to the customer's NLSL(s).  
6 The customer is required to take a minimum of a 2 percent level of service (the default  
7 election) and can elect up to a maximum of a 5 percent level of service. The service election  
8 must be made in whole percentage amounts (*e.g.*, 2, 3, 4, or 5 percent), and meet deadline  
9 requirements as defined in the GRSPs and the customer's contract . The monthly NR ESS  
10 Capacity Charge is calculated as the measured maximum actual hourly load of the NLSLs  
11 for a month multiplied by the customer's level of service multiplied by the applicable  
12 monthly NR demand rate. A NR Data Sharing Discount of 10 percent may also apply to the  
13 NR ESS Capacity Charge if the customer elects and meets the data sharing requirements as  
14 described in the GRSPs. A customer purchasing NR ESS and receiving the NR Data Sharing  
15 Discount may be eligible to further offset its NR ESS Capacity Charge by providing BPA  
16 access to capacity, via a demand or a resource response, based on terms and conditions  
17 negotiated between BPA and the customer.

18  
19 A monthly check is applied to ensure that the customer capacity use in any hour of the  
20 month did not exceed the monthly amount of capacity purchased from BPA through NR  
21 ESS. If the actual capacity used in an hour exceeds the amount of capacity purchased, then  
22 an Unauthorized Increase Charge (UAI) will apply.

23  
24 The energy component, the NR ESS Energy Charge either credits or debits the customer for  
25 the difference between energy amounts supplied by the customer's non-federal resources  
26 serving NLSLs and the measured actual load of the NLSLs in every hour. The NR ESS

1 Energy Charge can be either positive or negative and is then calculated as the NR ESS  
2 Energy Billing Determinant multiplied by the NR ESS Energy Rate. The NR ESS Rate is  
3 equal to the hourly LAP price for BPA as determined by the Market Operator (MO) under  
4 Section 29.11(b)(3)(C) of the MO Tariff for the same hour as the calculated NR ESS Billing  
5 Determinant. In the event of a Market Contingency pursuant to Section 10 of Attachment Q  
6 to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest. *See 2026*  
7 *Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.J.1(b)(2).*

## 8

### 9 **5.7 Resource Remarketing for Individual Customers**

10 The Remarketing Credit conveys the value BPA receives when it remarkets 1) committed  
11 Tier 2 purchases in excess of need, and 2) non-federal resources to which DFS applies that  
12 are temporarily in excess of need. The excess power is created when commitments to  
13 purchase are made prior to establishing need in the RHWM Process. *See 2026 Power Rate*  
14 *Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.K.*

#### 15

#### 16 **5.7.1 Tier 2 Remarketing**

##### 17 **5.7.1.1 Tier 2 Remarketing for Load Following Customers**

18 Section 10 of the CHWM contract states that a Load Following customer may elect to have  
19 BPA remarket its Tier 2 rate purchase amount in the event its Above-RHWM Load as  
20 forecast for an upcoming rate period year is less than the sum of its Tier 2 rate purchase  
21 amounts and new resource amounts. The Load Following customer must provide BPA  
22 notice of such election by October 31 of the year preceding the rate period for which the  
23 customer elects to have BPA remarket its Tier 2 purchase amount.

1 **5.7.1.2 Tier 2 Remarketing for Slice/Block or Block Customers**

2 Section 10 of the CHWM contract states that a Slice/Block or Block customer may elect to  
3 have BPA remarket its Tier 2 rate purchase amount in the event its forecast Net  
4 Requirement for the upcoming fiscal year is less than the sum of its RHWM and Tier 2 rate  
5 purchase amounts. Notice of such election must be provided by August 31 of each fiscal  
6 year for the upcoming fiscal year.

7  
8 **5.7.1.3 Calculating the Remarketed Tier 2 Proceeds for Load Following and**  
9 **Slice/Block or Block Customers**

10 Section 6.4 of the TRM states that if BPA remarkets a customer's Tier 2 purchase obligation  
11 pursuant to the CHWM contract, BPA will credit the proceeds from the remarketing (net of  
12 any remarketing costs) to such customer. TRM, BP-12-A-03. The customer must continue  
13 to pay for the entire purchase at the appropriate Tier 2 rate.

14  
15 The remarketed Tier 2 proceeds are computed for Load Following customers using 1) the  
16 remarketed amount of Tier 2 service (in megawatthours) plus real power losses, and 2) the  
17 Remarketing Value determined in accordance with Section 3.2.6 above.

18  
19 After notice is provided by a Slice/Block or Block customer, the remarketed Tier 2  
20 proceeds will be computed for that customer using 1) the remarketed amount of Tier 2  
21 service (in megawatthours) plus real power losses, and 2) the flat annual equivalent  
22 market price forecast after the time the notice is provided to BPA, for the applicable fiscal  
23 year, plus any additional costs incurred by BPA in purchasing power from other entities.

1 The annual remarketing proceeds for each customer are divided by 12 to compute a flat  
2 monthly credit that is applied to the customer's bill. No Load Following customers are  
3 forecast to have monthly remarketing Tier 2 proceeds for FY 2026, FY 2027 and FY 2028.

4  
5 Slice/Block and Block customers' monthly remarketed Tier 2 proceeds are calculated in the  
6 annual Net Requirements process, which occurs after the Section 7(i) process concludes.

## 7 8 **5.7.2 Non-Federal Resource Remarketing**

### 9 **5.7.2.1 Non-Federal Resource with DFS for Load Following Customers**

10 Section 10 of the CHWM contract states that a customer may elect to remove a new  
11 non-federal resource in the event its Above-RHWM Load, as forecast for an upcoming rate  
12 period year, is less than the sum of its Tier 2 rate purchase amounts and New Resource  
13 amounts. A Load Following customer must provide BPA notice of such election by  
14 October 31 of the year preceding the rate period for which the customer elects to remove  
15 its new non-federal resource. Section 10.5 of the CHWM contract states that BPA shall  
16 remarket the amounts of removed resources for which the customer purchases DFS in the  
17 same manner BPA remarkets Tier 2 rate purchase amounts. The customer will continue to  
18 pay for DFS on the entire resource amount that is applied to load and any portion of the  
19 resource remarketed by BPA.

### 20 21 **5.7.2.2 Non-Federal Resource with DFS for Slice/Block or Block Customers**

22 Section 10 of the CHWM contract states that a customer may elect to remove a new  
23 non-federal resource in the event its forecast Net Requirement for the upcoming fiscal year  
24 is less than the sum of its RHWM, Tier 2 rate purchase amounts, and new resource  
25 amounts. Notice of such election must be provided by August 31 of each fiscal year for the  
26 upcoming fiscal year. Additionally, Slice/Block and Block customers are responsible for

1 remarketing removed new resource amounts unless such resource is supported with DFS.  
2 Section 10.9 of the CHWM contract states that BPA shall remarket the amounts of removed  
3 resources for which the customer purchases DFS in the same manner BPA remarkets Tier 2  
4 rate purchase amounts.

5  
6 The customer will continue to pay for DFS on the entire resource amount that is applied to  
7 load and any portion of the resource remarketed by BPA.

8  
9 **5.7.2.3 Calculating the DFS Remarketing Proceeds for Load Following and**  
10 **Slice/Block or Block Customers**

11 The DFS remarketing proceeds are computed for Load Following customers using the  
12 Remarketing Value determined in accordance with Section 3.2.6 above for the applicable  
13 fiscal year. The DFS remarketing proceeds are computed for Slice/Block and Block  
14 customers using the flat annual equivalent market price forecast, as determined by BPA  
15 after the time the notice to remarket has been received, for the applicable fiscal year, plus  
16 any additional costs incurred by BPA in purchasing power from other entities.

17  
18 For each applicable non-federal resource to which DFS applies, the billing determinant is  
19 1) the customer's total non-federal resource, less 2) the amount of the customer's  
20 non-federal resource needed to meet Above-RHWM Load, as reflected in the customer's  
21 CHWM contract Exhibit A, when updated.

22  
23 For each resource, the DFS Remarketing Credit will be the product of multiplying the DFS  
24 remarketing rate by the DFS Remarketing Billing Determinant for each applicable year of  
25 the rate period. The annual value is divided by 12 to calculate a flat monthly credit. Power  
26 Rates Study Documentation, BP-26-FS-BPA-01A, Table 5.2 shows the forecast monthly DFS

1 Remarketing Credits that are calculated for the individual resources to which the DFS  
2 Remarketing Credit is applied for Load Following customers. Slice/Block and Block  
3 customers' DFS remarketing credits are calculated in the annual Net Requirements process,  
4 which occurs after the Section 7(i) process concludes.  
5

#### 6 **5.7.2.4 Resource Remarketing Service**

7 Exhibit D of the CHWM contract for Load Following customers offers an optional service for  
8 customers that have purchased non-federal resources in anticipation of future need. At the  
9 customer's request and with BPA's agreement, BPA will remarket the excess non-federal  
10 resource amounts on the customer's behalf until the customer's need meets or exceeds the  
11 non-federal resource amount. To qualify for this service, the customer must also request  
12 DFS for the non-federal resource. The DFS Charges will be applicable to both the  
13 non-federal resource amounts the customer dedicates to its load and any portion that BPA  
14 remarkets on the customer's behalf.  
15

#### 16 **5.7.2.4.1 RRS Credits**

17 RRS is administered in accordance with GRSP II.I.7 and includes the following components:

- 18 • RRS Rate. For each non-federal resource, the rate will be based on the Remarketing  
19 Value determined in accordance with Section 3.2.6.
- 20 • RRS Billing Determinant. The RRS Billing Determinant will be the annual average  
21 megawatt Resource Remarketed Amounts in the customer's CHWM contract  
22 Exhibit D (when updated).
- 23 • RRS Credit. For each resource, the RRS Credit will be the product of multiplying the  
24 RRS rate by the RRS Billing Determinant for each applicable year of the rate period.  
25 The annual value is divided by 12 to calculate a flat monthly credit.

- RRS Fee. The fee for providing RRS to customers is determined on a case-by-case basis.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

## **5.8 Transfer Service**

About half of BPA's power customers are served by the transmission systems of third parties (entities other than BPA). Under the CHWM contract, BPA must acquire transmission services from these third-party transmission providers to deliver federal power to BPA's power customers. This third-party transmission service is commonly referred to as Transfer Service. For information about Transfer Service, see Section 6 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.L.

## **5.9 Rate Payment Options**

### **5.9.1 Flexible PF Rate Option**

The Flexible PF rate option, offered at BPA's discretion, allows PF-26 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the PF-26 rate schedule. See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.W.

### **5.9.2 Priority Firm Power Shaping Option**

If requested, BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to reshape charges within each year of the rate period to mitigate adverse cash flow effects on the customer. Such reshaping of charges must recover the same number of dollars on a net present value basis within the fiscal year as would have been recovered without the reshaping. The reshaping of the

1 payments will be agreed upon between BPA and the customer prior to the start of the rate  
2 period. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.X.

### 3 4 **5.9.3 Flexible NR Rate Option**

5 The Flexible NR rate option, offered at BPA's discretion, allows NR-26 rates and billing  
6 determinants to be modified to accommodate a customer's request to change the way  
7 power is charged under the NR-26 rate schedule. *See* 2026 Power Rate Schedules and  
8 GRSPs, BP-26-A-01-AP01, GRSP II.Y.

### 9 10 **5.10 Unanticipated Load Service**

11 ULS applies to any request for Firm Requirements Power received after February 1, 2025,  
12 that results in an unanticipated increase in a customer's load placed on BPA during the  
13 FY 2026-2028 rate period. Contractual obligations that result from a request for service  
14 under Section 9(i) of the Northwest Power Act also will be considered ULS. 16 U.S.C.  
15 § 839f(i). ULS may also apply to a customer that adds load through retail access, including  
16 load that was once served by the customer and returns under retail access. *See* 2026  
17 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M.

#### 18 19 **5.10.1 PF Unanticipated Load Service**

20 The energy rate is equal to the greater of the following: 1) the PF Tier 1 Equivalent rate for  
21 the applicable diurnal period in GRSP II.AA; or 2) the projected market price for the  
22 applicable diurnal period calculated after a request for ULS is made plus any additional  
23 costs incurred by BPA in purchasing power from other entities. *See* Section 5.14 below for  
24 a description of the PF Tier 1 Equivalent rates. The PF ULS also includes a demand charge,  
25 which uses the PF-26 demand rate. The ULS under the PF-26 Rate Schedule is specified in  
26 GRSP II.M.2. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

1 **5.10.2 NR Unanticipated Load Service**

2 The energy rate is equal to the greater of 1) the NR energy rate for the applicable diurnal  
3 period; or 2) the projected market price for the applicable diurnal period calculated after a  
4 request for ULS is made plus any additional costs incurred by BPA in purchasing power  
5 from other entities. See Section 4.2.1 above for a description of the NR energy rates. The  
6 NR ULS also includes a Demand Charge, which uses the NR-26 Demand Rate. The ULS  
7 under the NR-26 Rate Schedule is specified in GRSP II.M.3. See 2026 Power Rate Schedules  
8 and GRSPs, BP-26-A-01-AP01, GRSPs.

9  
10 **5.10.3 FPS Unanticipated Load Service**

11 Under the FPS-26 rate schedule, the Resource Replacement (RR) rate or a projected market  
12 price will be applied to ULS for circumstances that cause an increase in a customer's load  
13 placed on BPA not anticipated in the rate case. Such circumstances could include, but are  
14 not limited to, delays in the online date of a customer's specified resource for  
15 Above-RHWM service; New Specified Resources that are 10 aMW or less and either  
16 experience permanent failure during the rate period or fail to come online; and transfer  
17 service customers that both 1) cannot secure Firm Network Transmission (NT) from  
18 source to sink for their dedicated non-federal resource to their Above-RHWM Load by the  
19 time power deliveries begin under the Regional Dialogue contract, and 2) are expected to  
20 face high TCMS Charges due to their reliance on Secondary Network Transmission while  
21 they pursue Firm Network Transmission. The provision of ULS will be at BPA's sole  
22 discretion.

23  
24 The energy rate is the greater of 1) the RR rate for the applicable diurnal period; or 2) the  
25 projected market price calculated after the time when the request for ULS is made plus any  
26 additional costs incurred by BPA in purchasing power from other entities. The RR rates are  
27 equal to the PF Tier 1 Equivalent rates. See Section 5.14 below for a description of the

1 PF Tier 1 Equivalent rates. The FPS ULS also includes a Demand Charge, which uses the  
2 Demand Rate in the PF, NR, and IP Rate Schedules. The ULS under the FPS-26 Rate  
3 Schedule is specified in GRSP II.M.4. *See 2026 Power Rate Schedules and GRSPs, BP-26-*  
4 *A-01-AP01, GRSPs.*

### 6 **5.11 Unauthorized Increase (UAI) Charges**

7 The UAI Charge is applied to customers taking more power from BPA than they are  
8 contractually entitled to take. The UAI demand rate is 1.25 times the applicable monthly  
9 demand rate. The UAI energy rate is the greater of 1) 150 mills/kWh, or 2) two times the  
10 hourly EIM LAP price for firm power for the hour in which the overage occurred. There is  
11 no cap for either demand or energy components. *See 2026 Power Rate Schedules and*  
12 *GRSPs, BP-26-A-01-AP01, GRSP II.N.*

### 14 **5.12 Residential Exchange Program Settlement Implementation**

15 The 2012 REP Settlement established a fixed stream of financial benefits payable to the  
16 IOUs beginning in FY 2012 and ending in FY 2028. These benefits are allocated among the  
17 IOUs based on their specific ASCs, PFX rates, and eligible residential and farm loads  
18 (Residential Loads). GRSPs II.S and II.T address two issues specific to the implementation  
19 of the 2012 REP Settlement. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01,*  
20 *GRSPs.*

21  
22 Pursuant to the terms of the 2012 REP Settlement, REP Residential Loads are normally  
23 calculated using a two-year monthly average of the IOUs' eligible residential and farm  
24 actual loads. The FY 2026, FY 2027 and 2028 Residential Load monthly averages for each  
25 IOU are listed in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.S,  
26 Table H.

1 GRSP II.T addresses the recalculation of the PFX rate in the event of a change to an IOU's  
2 ASC. *See* 2026 Power Rate Schedules and GRSPs, BP-26-EFSBPA-10, GRSPs. Calculation of  
3 the PFX rate is described in detail in Section 4.1.6 above. The PFX rate calculation is  
4 dependent upon, among other factors, the IOUs' Final ASCs. ASCs are determined outside  
5 the rate proceeding in an ASC Review Process that BPA conducts pursuant to the 2008 ASC  
6 Methodology (ASCM). *See* ASCM, 18 C.F.R. § 301 *et seq.* (2008). Forecast ASCs for  
7 participating IOUs and participating COUs are used for establishing rates in the Initial  
8 Proposal. *See* Section 8. Final ASCs are determined coincident with the Final Proposal and  
9 are incorporated therein. An IOU's Final ASC can change after final rates are set, although  
10 such changes are rare. In the event of such a change, the PFX rate must be recalculated for  
11 each REP participating utility. GRSP II.T describes the process for such recalculation.  
12 *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

13

### 14 **5.13 Cost Contributions**

15 In accordance with Section 7(j) of the Northwest Power Act, BPA provides the approximate  
16 cost contributions of different resource categories to BPA's rates for the sale of energy and  
17 capacity. 16 U.S.C. § 839e(j). The rate schedules also indicate the cost of resources BPA  
18 acquires to meet load growth and the relationship of such cost to BPA's average resource  
19 cost. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.Z.

20

### 21 **5.14 PF Tier 1 Equivalent Rates**

22 For use in contracts that have rates tied to a traditional PF HLH/LLH rate design without  
23 tiering, the PFp Tier 1 Equivalent rates consist of 12 HLH energy rates, 12 LLH energy  
24 rates, and 12 demand rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load  
25 Shaping rates less a scalar. The scalar is a single mills per kilowatthour value that adjusts  
26 the Load Shaping rates to a level at which the PFp Tier 1 equivalent energy rates, in

1 conjunction with the demand revenue, would collect the Tier 1 revenue requirement  
2 allocated to the PFp Non-Slice loads (the Composite cost pool plus the Non-Slice cost pool).  
3 This mills per kilowatthour value is equivalent to the Tier 1 load shaping true up rate  
4 (LSTUR). This calculation is shown in Power Rates Study Documentation, BP-26-FS-  
5 BPA-01A, Table 3.1.8.5. The Demand rates are equal to the Tier 1 Demand rates. The  
6 PF Tier 1 Equivalent rates are subject to adjustment during the rate period to reflect the  
7 Power CRAC, the Power RDC, and the Power FRP Surcharge. *See 2026 Power Rate*  
8 *Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.AA.*

### 9 10 **5.15 Washington Cap-and-Invest Program Charge**

11 This charge will be applicable if BPA becomes the First Jurisdictional Deliverer (FJD) in the  
12 Washington Cap-and-Invest Program. If BPA elects to be the FJD, BPA presumes that  
13 customers will 1) register to receive no-cost allowances from the Washington Department  
14 of Ecology and 2) transfer to BPA their no-cost allowances that they receive from the  
15 Washington Department of Ecology for emissions forecasted for federal power deliveries.  
16 If this does not occur, the customer will be subject to the new rate and charged for the cost  
17 that BPA incurs purchasing allowances to cover emissions for federal service to its load  
18 plus a 25 percent cost adder. *See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-*  
19 *AP01, GRSP II.AB.*

### 20 21 **5.16 Resource Adequacy Service**

22 This service will be applicable during any period in which BPA is a binding participant in  
23 the Western Resource Adequacy Program (WRAP) Binding Program. The Resource  
24 Adequacy Service includes two components 1) a 4.48 mills/kWh credit for Load Following  
25 customers that use non-federal resources to serve Above-RHWM Load that meet the WRAP  
26 forward-showing qualifying capacity capability (QCC) requirements, and 2) a

1 4.48 mills/kWh charge for Load Following customers with NLSLs that do not submit to BPA  
2 an approved exclusion attestation for the NLSL or provide QCC resource information for  
3 any non-federal resources serving the NLSL. *See* 2026 Power Rate Schedules and GRSPs,  
4 BP-26-A-01-AP01, GRSP II.AC. This rate is based on the Operating Reserves - Supplemental  
5 rate, converted to a kilowatthour figure, summed by the number of days during the binding  
6 period, and spread over an annual Energy Billing Determinant.

## 6. TRANSFER SERVICE

### 6.1 Introduction

More than half of BPA's power customers are served by the transmission systems of third parties; *i.e.*, entities other than BPA. Under the CHWM contracts, BPA must acquire transmission services from these third-party transmission providers to deliver federal power to BPA's power customers. This third-party transmission service is commonly referred to as Transfer Service.

Transfer Service customers may be subject to one or more separate charges from BPA:

1) the Transfer Service Operating Reserve Charge, 2) the Transfer Service Regulation and Frequency Response Charge, and 3) the Transfer Service Regional Compliance Enforcement Charge. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.L. In addition to these charges, Transfer Service customers are responsible for the cost of any distribution upgrades associated with their respective PODs, as provided in the Supplemental Direct Assignment Guidelines. *Id.* at GRSP I.E. BPA will continue to follow the cost allocation methodology developed in BP-16 for Southeast Idaho Load Service.

### 6.2 Supplemental Guidelines

The Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements address how BPA will recover the costs for facility expansions and upgrades on third-party transmission systems for transfer service customers. The Supplemental Guidelines, in conjunction with the Transmission Services Facility Ownership and Cost Assignment Guidelines, are used to determine whether and in what way specific facility or expansion costs should be assigned to particular transfer service customers. *Id.*

### 6.3 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is designed to compensate BPA for the cost of acquiring operating reserves assessed by third-party transmission providers and non-BPA balancing authorities for service to transfer service customers' loads. Assessment of the Transfer Service Operating Reserve Charge is conditioned on the satisfaction of two criteria:

1. BPA serves the power customer by Transfer Service; and
2. The Transfer Service customer is not already paying BPA for operating reserves for the customer's load under the ACS-24 rate schedule.

The Transfer Service Operating Reserve rates are the same as the ACS-26 rates for operating reserves that BPA charges customers that have load in the BPA balancing authority area (BAA); *i.e.*, the Transfer Service Spinning Operating Reserve rate is equal to the ACS-26 Operating Reserve – Spinning Reserve service rate, and the Transfer Service Supplemental Operating Reserve Charge is equal to the ACS-26 Operating Reserve – Supplemental Reserve service rate. The monthly billing determinant for both Transfer Service Operating Reserves Charges is the amount of the customer's metered load served by transfer (non-BPA BAA load).

To compute a revenue forecast for these charges, the forecast TRL of BPA customers served under Transfer Service is aggregated for each Transfer Service provider. These loads are responsible for operating reserves charges (spinning and supplemental) and are applied to Transfer Service customers in the same manner as operating reserves are applied to directly connected customers under ACS-26.

1 **6.4 Transfer Service Regulation and Frequency Response Charge**

2 The Transfer Service Regulation and Frequency Response Charge is designed to  
3 compensate BPA for the cost of acquiring regulation and frequency response service  
4 assessed by third-party transmission providers and non-BPA BAAs for service to transfer  
5 service customers' loads. Assessment of the Transfer Service Regulation and Frequency  
6 Response Charge is conditioned on the satisfaction of two criteria:

- 7 1. BPA serves the power customer by Transfer Service; and  
8 2. The Transfer Service customer is not already paying BPA for regulation and  
9 frequency response for the customer's load under the ACS-26 rate schedule.

10  
11 The Transfer Service Regulation and Frequency Response rate is equal to the ACS-26 rate  
12 for regulation and frequency response that BPA charges customers with load in the BPA  
13 BAA. The monthly billing determinant for the Transfer Service Regulation and Frequency  
14 Response Charge is the amount of the customer's metered load served by transfer  
15 (non-BPA BAA load).

16  
17 To compute a revenue forecast for these charges, the forecast TRL of BPA customers served  
18 under Transfer Service is aggregated for each Transfer Service provider. These loads are  
19 billed at the ACS-26 Regulation and Frequency Response rate.

20  
21 **6.5 Revenue Received from Transfer Service Charges**

22 Revenue received from Transfer Service Charges includes revenues associated with  
23 Transfer Service Operating Reserve and Regulation and Frequency Response service, and  
24 any other charges for regional compliance as outlined in Section 6.7 below. *See Power*  
25 *Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.5, line 244.* These revenues  
26 offset the ancillary service costs Power Services will pay to third-party transmission

1 systems for providing similar services, which are included as a cost in the Power Revenue  
2 Requirement. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.2,  
3 lines 56-58.

## 4 5 **6.6 Transfer Service Regional Compliance Enforcement Charge**

6 The Transfer Service Regional Compliance Enforcement Charge applies to all transfer  
7 service customer loads located outside of the BPA BAA. The Transfer Service Regional  
8 Compliance Enforcement Charge is a separate stand-alone charge.

### 9 10 **6.6.1 Background on Regional Compliance Enforcement Charge**

11 The Regional Compliance Enforcement Charge recovers costs associated with funding the  
12 North American Electric Reliability Organization (NERC) and the regional entity, which is  
13 the Western Electricity Coordinating Council (WECC). WECC develops and assesses a  
14 charge to loads located in BAAs within the Western Interconnection to support its regional  
15 operations. The charge is based on a Net Energy for Load (NEL) value, which includes all  
16 loads within a BAA, including system losses. Each BAA submits its NEL to WECC yearly.  
17 WECC adds the NEL amounts for all BAAs to identify a total NEL for all loads in the Western  
18 Interconnection. The annual revenue requirement for WECC is then divided by the total  
19 NEL to establish a dollars-per-megawatthour assessment.

### 20 21 **6.6.2 Regional Compliance Enforcement Assessment**

22 The Regional Compliance Enforcement Charge is assessed to the individual loads identified  
23 in the NEL data submitted by the BAAs. The format of each BAA's NEL submission to WECC  
24 varies across the region; *i.e.*, some BAAs identify each individual customer load in their NEL  
25 submissions, including both native and non-native load. In the past for these BAAs, WECC  
26 would issue an invoice to each customer for WECC Charges. Other BAAs identify and

1 submit single load quantities for their BAAs, with no differentiation between native and  
2 non-native loads. In these instances, the BAA receives a single invoice from WECC for all  
3 loads in the BAA. BPA's transfer service customer loads are located in BAAs that report in  
4 both manners.

### 6 **6.6.3 BPA's Transfer Services Regional Compliance Enforcement Charge**

7 For FY 2026-2028, WECC will bill Power Services for all NEL quantities reported by the  
8 BAAs that are associated with transfer service customer loads outside the BPA BAA. BPA  
9 will recover this billed amount from all Transfer Service customer loads located outside of  
10 the BPA BAA through the Transfer Service Regional Compliance Enforcement Charge,  
11 regardless of how each BAA reports the Transfer Service customer's load in its NEL  
12 submission.

### 14 **6.6.4 Regional Compliance Enforcement Charge**

#### 15 **6.6.4.1 Regional Compliance Enforcement Revenue Requirement**

16 To forecast the BPA revenue requirement for the Transfer Service Regional Compliance  
17 Enforcement rate, total NEL reported to WECC is computed for BPA Transfer Service  
18 customer loads outside BPA's BAA. The 2024 WECC NEL assessment list is used to identify  
19 specific transfer service customers by name, their corresponding NEL amounts, and NEL  
20 amounts associated with only BPA by the reporting BAAs. All of these NEL amounts are  
21 then summed to establish a total transfer service NEL value. The NEL quantities include  
22 losses, as do the NEL quantities WECC uses to assess its charges. The 2024 WECC NEL  
23 assessment is based on 2023 load information, which is the most current information  
24 available for forecasting BPA's WECC assessment for transfer service customers for  
25 FY 2026-2028.

1 The revenue requirement for the Transfer Service Regional Compliance Enforcement rate  
2 is \$342,459 and is computed by summing all individual assessment amounts as calculated  
3 by WECC and given to BPA. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
4 Table 6.1.

#### 6.6.4.2 Regional Compliance Enforcement Rate Calculation

7 The Transfer Service Regional Compliance Enforcement rate is computed by dividing the  
8 above revenue requirement by the total of all BPA Transfer Service customers' load from  
9 outside the BPA BAA. All non-BPA BAA Transfer Service customer loads are included,  
10 regardless of NEL reporting standards. For FY 2026-2028 this quantity of 6,583,287 MWh  
11 is used to calculate the Transfer Service Regional Compliance Enforcement rate of  
12 0.05 mills/kWh.

#### 6.7 Southeast Idaho Load Service Cost Allocation

15 From 1989 to 2016, BPA used an exchange agreement with PacifiCorp and a transmission  
16 wheeling agreement to deliver power to BPA's preference customers in Southeast Idaho.  
17 The exchange agreement with PacifiCorp expired in June 2016. Because of limited  
18 transmission capability between BPA's system and BPA's Southeast Idaho customers, BPA  
19 entered into five-year market purchases as part of an interim plan of service for a portion  
20 of BPA's transfer customer load located in Southeast Idaho. The first interim plan of  
21 service included two, five-year fixed-price market purchases from July 2016 through June  
22 2021. The second interim plan of service included five-year market purchases based at  
23 index beginning July 2021 through June 2026. The assumptions associated with the second  
24 interim plan have been carried forward to FY 2027 and FY 2028.

1 Due to the index pricing structure of these purchases, for FY 2021-2026, costs will not be  
2 allocated to the Composite cost pool as in the BP-20 rate case where a fixed market price  
3 was used to determine the delta between the forward market and the price at which the  
4 purchases were made. In the previous five-year interim service plan, the fixed price of the  
5 market purchases, less a market delta (difference), was allocated to balancing purchases,  
6 which are assigned to the Non-Slice cost pool. The remaining cost of the purchases, the  
7 market delta, was allocated to the Transfer Service budget, which is a component of the  
8 Composite cost pool.

9  
10 For the five-year interim service plan, starting in July 2021, BPA has acquired market  
11 purchases based at index. One market index purchase includes an adder to the Mid-C  
12 index. An adder is a fixed amount of additional dollars added to the Mid-C Index at the time  
13 energy is delivered. Therefore, if at the time of delivery the Mid-C index was \$35 and the  
14 adder was \$2, then the total transaction price would be \$37 for that interval. The second  
15 index purchase includes a Mid-C minus component. Using the example above, and  
16 replacing the adder with a minus component, the result of the total transaction price for  
17 that interval would be \$33. When we net the adder and minus component together by  
18 multiplying the hours, megawatts, and index addition or subtraction for each contract there  
19 is a net benefit of \$663,380. Unlike the first interim service plan where the fixed price  
20 resulted in a market delta cost, the offsetting nature of the Mid-C index adder and minus  
21 component results in no added cost to BPA related to these market purchases. Since there  
22 is no added cost, the full result will be included in the Non-Slice cost pool.

## 7. SLICE TRUE-UP

### 7.1 Slice True-Up Adjustment

Slice customers are subject to 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). *See* TRM, BP-12-A-03, § 2.7.

### 7.2 Composite Cost Pool True-Up

The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Composite cost pool for each fiscal year. For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite cost pool will be calculated as shown in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.1. The dollar amount calculated may be positive or negative. The Composite Cost Pool True-Up Table shows the forecast expenses, revenue credits, and adjustments that form the basis for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. *Id.* at GRSP II.R, Table F.

The following sections discuss the treatment of certain expenses, revenue credits, and adjustments included in the Composite Cost Pool True-Up.

#### 7.2.1 System Augmentation Expenses

System augmentation expenses are included in the FY 2026-2028 Composite cost pool. Some of these augmentation expenses are a cost for service to Non-Slice customers' Above-

1 RHWL Load that is served at Load Shaping rates. For a description of these system  
2 augmentation expenses, see Section 3.2.4.3.2 above.

3  
4 System augmentation expenses are not subject to the Composite Cost Pool True-Up.  
5 However, implicit in the Composite Cost Pool True-Up of the Firm Surplus and Secondary  
6 Adjustment (for Unused RHWL) and the DSI Revenue Credit are adjustments that reflect  
7 the effects of additional power purchases (or lack thereof) or additional power sales to the  
8 market. Sections 3.2.4.2 and 7.2.3 describe the treatment of the Firm Surplus and  
9 Secondary Adjustment (for unused RHWL) for Composite Cost Pool True-Up purposes.  
10 Section 7.2.4 below describes the DSI revenue credit.

11  
12 BPA's purchase of output from the Klondike III resource is a Tier 1 augmentation expense,  
13 and the Composite cost pool includes the cost of RSS and RSC applicable to Klondike III.  
14 Because the RSS and RSC Charges financially convert the variable output of Klondike III to a  
15 firm annual block of power and are committed to in advance, the augmentation expense  
16 and RSS and RSC costs associated with generation output from the Klondike III resource  
17 are not subject to the Composite Cost Pool True-Up.

## 18 19 **7.2.2 Balancing Augmentation Load Adjustment**

20 The Balancing Augmentation Load Adjustment can result in a positive or negative credit to  
21 the Composite cost pool. Section 3.2.4.3 describes the Balancing Augmentation Load  
22 Adjustment, the circumstances that would result in a credit, and the circumstances that  
23 would result in a negative credit. The Balancing Augmentation Load Adjustment is not  
24 subject to the Composite Cost Pool True-Up.

1 **7.2.3 Firm Surplus and Secondary Adjustment (from Unused RHW M)**

2 The Firm Surplus and Secondary Adjustment (from Unused RHW M) is subject to the  
3 Composite Cost Pool True-Up. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-  
4 AP01, GRSP II.R.1(b). This adjustment reflects the fact that when the sum of actual TOCAs  
5 is greater than the sum of forecast TOCAs, additional power is sold to customers at the  
6 Composite Customer rate, and it is assumed that BPA incurs additional costs in the form of  
7 forgone market sales or increased power purchases. Likewise, when the sum of actual  
8 TOCAs is less than the sum of forecast TOCAs, less power is sold to customers at the  
9 Composite Customer rate, and it is assumed that BPA sells more power in the market or  
10 faces lower power purchase costs.

11  
12 **7.2.4 DSI Revenue Credit**

13 The forecast costs associated with service to the DSIs are included in the Composite cost  
14 pool. *See* TRM, BP-12-A-03, § 3.2.1.3. DSI revenues received by BPA are included in the  
15 Composite cost pool as credits. The DSI Revenue Credit thus is subject to the Composite  
16 Cost Pool True-Up. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01,  
17 GRSP II.R.1(c).

18  
19 The calculation of the DSI Revenue Credit starts with the forecast DSI revenue credit, which  
20 is adjusted to calculate the actual DSI revenue credit. When actual DSI sales are greater  
21 than the rate case forecast DSI sales, it is assumed that additional power is sold to the DSIs  
22 at the IP rate, and BPA incurs additional costs in the form of forgone market sales or  
23 increased power purchases. The adjustment to the forecast DSI revenue credit reflects  
24 both the revenues from the additional power sold to the DSIs and the additional costs that  
25 are incurred. Likewise, when actual DSI sales are less than the rate case forecast DSI sales,  
26 it is assumed that BPA sells less power to DSIs at the IP rate and sells more power in the  
27 market, or it is assumed that such power may be used to meet BPA obligations so that

1 fewer power purchase costs are incurred. The adjustment to the forecast DSI revenue  
2 credit reflects these effects. The adjustment also includes any DSI take-or-pay revenues  
3 recorded by BPA, if applicable.  
4

#### 5 **7.2.5 Interest Earned on the Bonneville Fund**

6 On the first day of the Slice contract, October 1, 2001, BPA had \$495.6 million in financial  
7 reserves attributed to the Power function. TRM Section 2.5 provides for an interest credit  
8 that BPA will allocate to the Composite cost pool based on the pre-FY 2002 (FY 2002 began  
9 on October 1, 2001) level of reserves. TRM Section 2.5 further provides that future  
10 circumstances may occur that make it reasonable and fair to make adjustments to the size  
11 of the base amount of financial reserves attributed to the Power function as of October 1,  
12 2001, for purposes of calculating the interest credit allocated to the Composite cost pool.  
13

14 BPA made several adjustments to the base reserve amount in setting the BP-14 rates, as  
15 shown in Table 5. In addition, there were adjustments made in FY 2018. The adjustments  
16 reflected in Table 5 are not amounts that have been shared with or collected from Slice  
17 customers through a prior Slice True-Up. As a result, these amounts are reflected as  
18 adjustments to the size of the base amount of financial reserves. As shown in Table 5,  
19 Line 32, the revised reserve amount for purposes of calculating the interest credit is  
20 \$586.596 million. BPA has not made any adjustments to the revised reserve amount from  
21 the BP-14 rate proceeding in setting the proposed BP-26 rates. The forecast interest credit  
22 for the Composite cost pool is \$18.891 million in FY 2026, \$17.369 million in FY 2027 and  
23 \$17.252 million in FY 2028. *See Power Rates Study Documentation, BP-26-FS-BPA-01A,*  
24 *Table 2.3.1.3.*  
25

1 The interest credit on the financial reserves amount is subject to the Composite Cost Pool  
2 True-Up. The actual interest credit calculated on the revised base amount of financial  
3 reserves can change from the forecast interest credit if there are changes in the factors  
4 used to calculate the forecast interest credit.

#### 6 **7.2.6 Bad Debt Expenses**

7 Bad debt expenses, if any, are allocated between the Composite cost pool and the Non-Slice  
8 cost pool, as specified in the TRM, BP-12-A-03, Table 2A. There is no forecast bad debt  
9 expense for the FY 2026-2028 period for ratemaking purposes. If a bad debt expense is  
10 identified and accounted for in BPA's actual audited financial reports for a given fiscal year,  
11 BPA will determine whether the expense should be included in the actual expenses and  
12 revenue credits that are allocable to the Composite cost pool in the applicable fiscal year of  
13 the rate period. If so, then the expense may be included for purposes of the Composite Cost  
14 Pool True-Up, and the bad debt expense would be allocated according to the principle of  
15 cost causation, as described generally in the TRM, BP-12-A-03, Section 2.1.

16  
17 Any bad debt expense associated with a sale to any customer that purchased federal power  
18 exclusively at the FPS-24 and FPS-26 rates would be excluded for Composite Cost Pool  
19 True-Up purposes. Bad debt expenses associated with sales of power at only these FPS  
20 rates are related solely to BPA's sales of surplus power after the inception of the Slice  
21 product and not to sales of requirements power. The expenses and revenues from such  
22 sales are included in the Non-Slice cost pool. *See* TRM, BP-12-A-03, § 2.2.3.

23  
24 Any bad debt expense associated with a sale to a customer that purchases power at only  
25 the PF or IP rate will be included for purposes of the Composite Cost Pool True-Up. The  
26 allocation to the Composite cost pool of any bad debt expense associated with a sale to a

1 customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer  
2 that purchases power at both the IP rate and the FPS rate, will be contingent on the  
3 circumstances of the particular instance of a full or partial non-payment of a power bill.

4  
5 Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up  
6 purposes if Slice customers paid for the bad debt expense through their Slice True-Up  
7 Adjustment Charge.

### 8 9 **7.2.7 Settlement and Judgment Amounts**

10 BPA payments or receipts of money related to settlements and judgments will be allocated  
11 on a case-by-case basis to either the Composite cost pool or the Non-Slice cost pool. If an  
12 amount (payment or receipt) is accounted for in BPA's actual audited financial reports for  
13 any given fiscal year (reports are produced after rates are set), BPA will determine whether  
14 such amount will be included or excluded for Composite Cost Pool True-Up purposes. Such  
15 a determination will be made based on the principle of cost causation. *See id.* § 2.1.

### 16 17 **7.2.8 Transmission Costs for Designated BPA System Obligations**

18 Transmission and Ancillary Services expenses are allocated between the Composite cost  
19 pool and the Non-Slice cost pool, as specified in the TRM, BP-12-A-03, Table 2A. The  
20 Transmission and Ancillary Services expenses associated with Designated BPA System  
21 Obligations are allocated to the Composite cost pool. Such Transmission and Ancillary  
22 Services expenses are not subject to the Composite Cost Pool True-Up.

23  
24 Transmission reservations are set aside for non-discretionary obligations (*e.g.*, Designated  
25 BPA System Obligations). Because Power Services does not know the actual amounts of  
26 transmission usage until the preschedule period for such obligations, the transmission

1 reservations for those obligations are purchased based on the maximum need for the year.  
2 Therefore, the forecast cost of the reservations for Designated BPA System Obligations is  
3 included in the Composite cost pool, and such costs are not subject to the Composite Cost  
4 Pool True-Up.

5  
6 Any revenues from the resale of transmission that appear to be the result of BPA sales of  
7 unused transmission inventory associated with set-aside transmission will be excluded for  
8 Composite Cost Pool True-Up purposes. Because the cost of additional transmission  
9 purchased (or of using Non-Slice transmission inventory) to serve Designated BPA System  
10 Obligations in excess of what was forecast in the ratemaking process is not included in the  
11 Composite Cost Pool True-Up, revenues from sales of surplus transmission inventory also  
12 are excluded from the Composite Cost Pool True-Up.

#### 14 **7.2.9 Power Services Third-Party Transmission and Ancillary Services**

15 These costs are associated with transmission or losses for federal generation telemetered  
16 into BPA's BAA and delivered under BPA's Open Access Transmission Tariff. These costs  
17 are tied to any federal resources or generation included in the RHWMTier 1 System  
18 Capability and delivered in the Slice product. Therefore, these costs are allocated to the  
19 Composite cost pool and are subject to the Composite Cost Pool True-Up.

#### 21 **7.2.10 Transmission Loss Adjustment**

22 A transmission loss adjustment is included in the Composite cost pool. Without such an  
23 adjustment, Slice customers would pay not only for real power losses (through loss return  
24 schedules to BPA) on the transmission of their Slice purchases, but also a proportionate  
25 share of losses on the transmission of non-Slice products. See Section 3.2.4.1 above for an

1 explanation of the calculation of this credit. The transmission loss adjustment is not  
2 subject to the Composite Cost Pool True-Up.

#### 3 4 **7.2.11 Resource Support Services Revenue Credit**

5 A credit for RSS revenue is included in the Composite cost pool. The credit is for revenues  
6 earned by uses of capacity to support resources that receive RSS. *See* Section 3.2.3.1.4  
7 above. This revenue credit is not subject to the Composite Cost Pool True-Up.

#### 8 9 **7.2.12 Generation Inputs for Ancillary and Other Services Revenue Credit**

10 The uses of the generating capacity available to BPA to support the transmission system  
11 and maintain reliability are generally referred to as generation inputs. Generation inputs  
12 include capacity-related and energy-related services that BPA uses to provide Ancillary and  
13 Control Area Services, support transmission, and maintain the reliability of the  
14 transmission system. These services include balancing reserve services, operating reserve  
15 services, synchronous condensing, generation dropping, redispatch service, station service,  
16 and U.S. Army Corps of Engineers (Corps)/Reclamation segmentation. A credit for  
17 Generation Inputs revenue is included in the Composite cost pool. *See* TRM, BP-12-A-03,  
18 Table 2, line 120, and Table 3.4, line 44. This revenue credit is subject to the Composite  
19 Cost Pool True-Up Table. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A,  
20 Table 9.3.

#### 21 22 **7.2.13 Tier 2 Rate Adjustments**

23 Tier 2 rate adjustments are ratemaking adjustments to the Composite cost pool to reflect a  
24 share of expenses incurred by Power Services that are allocable to all power sold. *See*  
25 Section 3.2.2 above. There are two types of rate adjustments: the Tier 2 overhead cost  
26 adder and the Tier 2 transmission scheduling service cost adder.

1 The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by  
2 Power Services. See Section 3.2.2.3. The Tier 2 overhead cost adder is included in the  
3 Composite cost pool. This adjustment is estimated for ratemaking purposes and is not  
4 subject to the Composite Cost Pool True-Up.

5  
6 The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative  
7 costs incurred by Power Services. For a description of this adjustment, see Section 3.2.2.2  
8 above. The forecast of this adjustment is included in the RSS revenue credit. This  
9 adjustment is not subject to the Composite Cost Pool True-Up.

#### 10 11 **7.2.14 Residential Exchange Program Expense**

12 Forecast REP benefits are included in the Composite cost pool for ratemaking purposes.  
13 The forecast of REP expense on the Composite Cost Pool True-Up Table is equal to the  
14 forecast of REP benefits expected to be paid to REP participants. The forecast REP expense  
15 is subject to the Composite Cost Pool True-Up.

#### 16 17 **7.2.15 Canadian Designated System Obligation Annual Financial Settlements**

18 The Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and BC Hydro  
19 that allows water transactions to be financially settled between them. The NTSA provides  
20 two mechanisms to settle the transaction benefits, which BPA designates as a system  
21 obligation: 1) energy deliveries during the year, and 2) a financial settlement based on the  
22 August 31 balance at the end of the fiscal year. The Short-Term Libby Agreement (STLA)  
23 and subsequent updates are agreements between the U.S. and Canada that allow water  
24 transactions to be financially settled between BPA, acting on behalf of the U.S., and  
25 BC Hydro, acting on behalf of Canada. The STLA does not have a provision to settle  
26 transactions by energy delivery. BPA designates the STLA as a system obligation, and the

1 financial settlement is based on the August 31 balance at the end of the fiscal year.  
2 Financial settlements in a fiscal year and the financial accrual amount recorded for the  
3 month of September of the same fiscal year are charged or credited to other power  
4 purchases, and Slice customers pay their share of the charge or receive their share of the  
5 credit through the Composite Cost Pool True-Up Table.

#### 7 **7.2.16 Participating Resource Scheduling Coordinator (PRSC) Net Credit**

8 In the EIM, when Power Services bids in participating resource amounts, any net credits, or  
9 charges, associated with balancing reserves will be included in the PRSC Net Credit line  
10 item under Revenue Credits. The PRSC Net Credit will be equal to the actual charges and  
11 credits allocated from the California Independent System Operator (CAISO) to Power  
12 Services as a PRSC multiplied by the following percentages calculated using data from the  
13 same time period in which the charges and credit were incurred: 1) Non-Regulating  
14 balancing capacity offered by Power Services in an hour, divided by 2) total amount of  
15 capacity bid into the EIM by Power Services in that same hour. For an hour in which Power  
16 Services offers incremental (*inc*) and decremental (*dec*) capacity into the EIM, there will be  
17 two percentages for the hour, one for *inc* capacity and one for *dec* capacity. The calculated  
18 percentages will be capped at 100 percent. Any CAISO charges or credits that are not  
19 associated with either a sale or purchase of power will be allocated as a monthly sum  
20 multiplied by the *inc* and *dec* ratio of balancing capacity to all capacity offered to the CAISO  
21 EIM for the same period.

22  
23 The PRSC Net Credit is subject to the Composite Cost Pool True-Up. The amount calculated  
24 as part of the True-Up process may be a negative number (a charge).

1 **7.2.17 Other Potential Adjustments**

2 A few new lines have been added to the Composite Cost Pool True-Up Table in the BP-26  
3 rate proceeding. New line items and other changes include:

- 4 1. Amortization of P2IP settlement payments
- 5 2. Long-Term funding Agreements (Accords)
- 6 3. FPS Real Power Losses, previously designated as Non-Slice
- 7 4. Other Augmentation is now included in Augmentation Purchases

8  
9 Consistent with the Update to BPA’s BP-26 Cost Projections, issued on July 14, 2025, cost  
10 projections in power rates associated with the Memorandum of Understanding filed on  
11 December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v.*  
12 *National Marine Fisheries Service*, 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were  
13 removed. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5.

14  
15 **7.3 Slice Cost Pool True-Up**

16 The Slice Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for  
17 the Slice cost pool, as described in TRM, BP-12-A-03, Section 2.7.2. Calculation of the  
18 Annual Slice Cost Pool True-Up is described in GRSP II.R.2 and is shown in GRSP Table G.  
19 See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01. Slice expenses and credits  
20 are forecast to be zero in FY 2026, FY 2027, and FY 2028. If there are any actual Slice  
21 expenses and credits incurred during the rate period, such expenses and credits will be  
22 subject to the Slice Cost Pool True-Up.

## 8. AVERAGE SYSTEM COSTS (ASC)

### 8.1 Overview of the Residential Exchange Program

The REP, established by Section 5(c) of the Northwest Power Act, was designed to provide residential and farm customers of Pacific Northwest utilities a form of access to low-cost federal power. 16 U.S.C. § 839c(c). Under the REP, BPA purchases power from each participating utility at that utility's ASC. The ASC (dollars per megawatthour or mills per kilowatthour is a rate determination that is calculated for each utility participating in the REP. (For ratemaking purposes, the power purchased by BPA is called "exchange resources.") BPA sells to the utility, in exchange for the power it purchases, an equivalent amount of electric power at BPA's Priority Firm Power Exchange (PFx) rate. (For ratemaking purposes, the power purchased by the utilities is called "exchange loads.")

The "exchange" transfers no actual power to or from BPA; it is an accounting transaction in which dollars are exchanged rather than electric power. However, to ensure proper cost allocations and rate determinations, RAM2026 models the REP as purchases of power by BPA (priced at the participants' respective ASCs) and simultaneous sales of power to the REP participants (priced at the participants' respective PFX rates).

BPA is implementing the 2012 REP Settlement with IOU exchange participants through REPSIA and with COU participants through RPSA. Total REP costs are included in rates for FY 2026-2028.

The 2012 REP Settlement established a fixed stream of REP benefits payable to the IOU REP participants beginning in FY 2012 and ending in FY 2028. 2012 REP Settlement, REP-12-A-02A. Individual IOU REP benefit determinations under the 2012 REP Settlement will continue to be calculated as under the traditional REP; that is, BPA will compare each

1 IOU's ASC for FY 2026-2028 with its respective BP-26 PFx rate and, if the difference is  
2 positive, multiply the difference by the IOU's exchange load to calculate its REP benefit (in  
3 dollars). *Id.* Similarly, pursuant to the RPSAs with the two COUs participating in the REP,  
4 BPA will compare each COU's ASC for FY 2026-2028 with its respective BP-26 PFx rate and,  
5 if the difference is positive, multiply the difference by its exchange load to calculate its REP  
6 benefit. The COUs' REP benefits are in addition to (*i.e.*, are not included in) the fixed stream  
7 of IOU REP benefits under the 2012 REP Settlement. *Id.* For a forecast of individual utility  
8 annual REP benefit payments for FY 2026-2028, see Table 6 of this Study.

## 9 10 **8.2 ASC Determinations**

11 BPA determines participating utilities' ASCs outside the rate proceeding in an ASC Review  
12 Process conducted pursuant to the substantive and procedural requirements of the 2008  
13 ASC Methodology (ASCM), 18 C.F.R. § 301, *et seq.* FERC granted final approval to the 2008  
14 ASCM on September 4, 2009.

15  
16 A utility's ASC for the rate period is calculated by dividing the utility's allowable resource  
17 costs and revenues (Contract System Cost) by its allowable load (Contract System Load).  
18 The quotient is the utility's rate period ASC. Contract System Cost is the sum of the utility's  
19 allowable generation-related and transmission-related costs and overheads; distribution-  
20 related costs are not included. Contract System Load is calculated as the total retail sales of  
21 a utility as measured at the meter, plus distribution losses, less any NLSLs, if applicable.

22  
23 Under the 2008 ASCM, the ASC for each utility may change if the utility adds a new  
24 resource, retires an existing resource, or adds an NLSL. However, under the 2012 REP  
25 Settlement, participating IOUs agreed not to submit ASC revisions based on new resources  
26 coming online or being removed during the Exchange Period (the Exchange Period is the

1 same as the rate period, currently FY 2026-2028). 2012 REP Settlement, REP-12-A-02A,  
2 § 6.4. Therefore, for COUs only, the ASC may change if the utility adds a new resource or  
3 retires an existing resource during the Exchange Period. The revised ASC takes effect in the  
4 month after a new resource comes online, an existing resource is retired, or a new NLSL  
5 begins taking service. The ASCs for the BP-26 rate period are shown in Table 8.1 of the  
6 Power Rates Study Documentation, BP-26-FS-BPA-01A.

7  
8 Under the 2012 REP Settlement, the IOU ASCs that are effective on the first day of the rate  
9 period will continue to be in effect throughout the Exchange Period, with the exception of  
10 the addition of an NLSL. 2012 REP Settlement Agreement, REP-12-A-02A. These “day-one”  
11 IOU ASCs are developed for use in establishing rates for the BP-26 rate period. Section II.T  
12 of the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, specifies how the PFX rate  
13 applicable to each REP participant will change if a revised ASC takes effect.

14  
15 The ASCs used in the BP-26 Final Proposal were determined in the separate ASC Review  
16 Processes and published in the Final ASC Reports on July 24, 2025. The ASCs reflected in  
17 the Final ASC Reports were based on REP Staff’s assessment of the utilities’ ASCs filings.  
18 BPA issued Final ASC Reports for eight utilities: Avista Utilities, Idaho Power Company,  
19 NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark  
20 County PUD, and Snohomish County PUD. These reports are available at:

21 [https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-](https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings)  
22 [utility-filings.](https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings)

### 23 24 **8.3 Residential Exchange Program Load**

25 Exchange loads are defined as a utility’s qualifying residential and farm consumer loads as  
26 determined in accordance with the utility’s RPSA or REPSIA.

1 Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical  
2 average for determining monthly exchange load, referred to as Residential Load, to  
3 calculate IOU REP benefits. 2012 REP Settlement, REP-12-A-02A, § 2 (“Residential Load”).  
4 For the BP-26 rate period, the historical years are calendar year (CY) 2023 and CY 2024.  
5 The monthly loads applicable to both years of the BP-26 rate period are shown in GRSP II.S,  
6 Table H. 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

7  
8 The COUs’ RPSAs do not specify the use of historical exchange loads in computing COU REP  
9 benefits; therefore, forecasts are used to estimate COU REP benefits for ratemaking  
10 purposes. For the COUs, the FY 2026-2028 exchange load forecasts are based on the  
11 exchange load information provided by the COUs in the ASC Review Process. Each COU’s  
12 exchange load forecast is adjusted for the COU’s Tier 1 percentage (if applicable), as  
13 required by the TRM. The Tier 1 percentage is defined as BPA’s forecast percentage of the  
14 COU’s load that is expected to be served by purchases of power at Tier 1 rates from BPA  
15 and from the COU’s Existing Resources for CHWM. COU REP benefits will be paid on actual  
16 residential and farm sales as adjusted by the Tier 1 percentage for each COU, as submitted  
17 after each month during the rate period. The monthly IOU Residential Loads and monthly  
18 forecast COU exchange loads are shown in Table 8.2 of the Power Rates Study  
19 Documentation, BP-26-FS-BPA-01A.

#### 20 21 **8.4 REP 7(b)(3) Surcharge Adjustment**

22 The REP § 7(b)(3) surcharge is a utility-specific addition to the base PFX rates that recovers  
23 each REP participant’s allocated share of rate protection provided pursuant to § 7(b)(2) of  
24 the Northwest Power Act. 16 U.S.C. § 839e(b)(2)-(3). Each REP participant’s initial 7(b)(3)  
25 surcharge is determined in the § 7(i) rate proceeding based on the base PFX rates, the ASCs,  
26 and the forecast exchange loads of all utilities assumed for ratemaking to participate in the

1 REP. *Id.* at § 839e(i). Each REP participant’s initial 7(b)(3) surcharge is displayed in  
2 Section 6.1 of the PF-26 rate schedule. 2026 Power Rate Schedules and GRSPs, BP-26-A-  
3 01-AP01, PF-26, § 6.1. Each participating utility’s 7(b)(3) surcharge is subject to change  
4 during the rate period if any participant’s ASC changes during the rate period due to the  
5 addition of an NLSL in the utility’s service territory. For COUs only, the addition or removal  
6 of a resource from the participant’s resource portfolio will also change its 7(b)(3)  
7 surcharge. The procedures for modifying the 7(b)(3) surcharges of all REP participants are  
8 codified in GRSP II.T. 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

9

## 9. REVENUE FORECAST

The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2026-2028, and the current fiscal year, FY 2025. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect (BP-24 rates), and the second uses proposed rates (BP-26 rates). The revenue forecasts are used to test whether current rates and proposed rates will recover the power revenue requirement. If the revenue test shows that revenues at current rates will not generate sufficient revenue to recover the power revenue requirement, new rates are calculated, and revenues at proposed rates are generated. *See* Power Revenue Requirement Study, BP-26-FS-BPA-02, §§ 3.2-3. Both forecasts are based on the Power Loads and Resources Study, BP-26-FS-BPA-03, forecast of firm loads for the current fiscal year and the rate period.

In addition to forecasts of revenues, this section of the Study presents power purchase expenses that are directly related to balancing purchases needed to meet load under different water conditions. Power purchases are included in the forecast for FY 2026-2028 and discussed in Section 9.5 below.

The revenue forecast includes revenue calculations for the current fiscal year, FY 2025, to help estimate the amount of financial reserves available to BPA at the beginning of the rate period. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2.2.1.

The revenue forecast is divided into four main categories: 1) revenues from gross sales, described in Section 9.1 below; 2) miscellaneous revenues, described in Section 9.2; 3) revenues from generation inputs for ancillary, control area, and other services, described in Section 9.3; and (4) U.S. Treasury credits, described in Section 9.4.

1 **9.1 Revenue Forecast for Gross Sales**

2 Gross Sales is Power Services' largest category of revenue. There are eight sources of  
3 revenue in this category:

- 4 1. PF power sales under the CHWM contracts, described in Section 9.1.1;
- 5 2. IP sales to DSIs, described in Section 9.1.2.1;
- 6 3. NR sales, described in Section 9.1.2.2;
- 7 4. Scheduling products under the FPS rate, described in Section 9.1.3;
- 8 5. Short-term market sales, described in Section 9.1.4;
- 9 6. Long-term contractual obligations, described in Section 9.1.5;
- 10 7. Canadian entitlement returns, described in Section 9.1.6; and
- 11 8. Other sales, described in Section 9.1.7.

12  
13 **9.1.1 Priority Firm Power Sales under CHWM Contracts**

14 For FY 2025, the revenues from PF power sales pursuant to CHWM contracts are calculated  
15 using the product of 1) forecast loads documented in the Power Loads and Resources  
16 Study, BP-26-FS-BPA-03, Section 2.2, and accompanying Power Loads and Resources  
17 Documentation, BP-26-FS-BPA-03A, Table 1.2.1 for energy, Table 1.2.2 for HLH, and  
18 Table 1.2.3 for LLH; and 2) PF-26 rates. Revenues from PF sales pursuant to CHWM  
19 contracts for FY 2025 are listed in Table 4 of this Study, lines 3-12, and in Power Rates  
20 Study Documentation, BP-26-FS-BPA-01A, Table 9.2, lines 3-12.

21  
22 For FY 2026, FY 2027 and FY 2028, revenues from PF sales pursuant to CHWM contracts  
23 are computed using the product of 1) forecast loads assuming normal weather,  
24 documented in the Power Loads and Resources Study, BP-26-FS-BPA-03, and  
25 accompanying Power Loads and Resources Documentation, BP-26-FS-BPA-03A; and 2) the  
26 appropriate PF rates derived by RAM2026. Inputs and results for the revenue forecast are

1 managed and calculated pursuant to the CHWM contracts using the Revenue Forecasting  
2 Application (RFA). Revenues are reported for Tier 1 Customer charges (Composite, Slice,  
3 and Non-Slice), Load Shaping, and demand, including the LDD and IRD credits, and any  
4 additional Tier 2 and/or RSS charges.

#### 6 **9.1.1.1 Composite and Non-Slice Customer Charges**

7 Revenues from each customer for the Composite and Non-Slice Customer Charges are  
8 based on the customer's TOCA and the customer's contractually specified products. There  
9 are no Slice charges for FY 2023-2025. Revenues obtained from the Composite and Non-  
10 Slice Customer Charges represent the majority of revenues from firm power sales under  
11 CHWM contracts for FY 2025-2028. The calculation of forecast Composite and Non-Slice  
12 revenues is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A,  
13 Tables 3.1.6.1-3. Composite and Non-Slice revenues for FY 2025-2028 are listed in Table 4  
14 of this Study, lines 3-4, and Power Rates Study Documentation, BP-26-FS-BPA-01A,  
15 Table 9.2, lines 3-4.

#### 17 **9.1.1.2 Load Shaping Charge**

18 The Load Shaping Charge reflects the costs and benefits of shaping the Tier 1 System  
19 Capability to the monthly/diurnal shape of a customer's below-RHWM load. A charge to  
20 the customer results when the customer's shaped load is greater than its share of the Tier 1  
21 System Output in any month for both HLH and LLH; the customer receives a credit from  
22 BPA when the opposite occurs. The Load Shaping Charge is described in Section 4.1.1.3  
23 above. The forecast of Load Shaping revenues for FY 2025-2028 is listed in Table 4 of this  
24 Study, line 6, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 6.

1 **9.1.1.3 Demand Charge**

2 The demand charge is applicable to customers purchasing Load Following or Block with  
3 shaping capacity products; for FY 2025-2028, there are no customers purchasing Block  
4 with shaping capacity. The demand charge is calculated using customer-specific  
5 information including actual Customer Tier 1 System Peak, average actual monthly below-  
6 RHWM load occurring in HLH, Contract Demand Quantities (CDQs), and Super Peak Credit  
7 (if applicable). Calculation of a customer’s demand charge is described in Section 4.1.1.2.2  
8 above. The demand revenue forecast for FY 2025-2028 is also shown in Table 4 of this  
9 Study, line 7, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 7.

10  
11 **9.1.1.4 Irrigation Rate Discount (IRD)**

12 The IRD is a rate credit available to eligible customers and provides a fixed rate discount on  
13 Tier 1 rates (the discount does not apply to loads served at Tier 2 rates). May through  
14 September eligible irrigation loads are identified in each customer’s CHWM contract. The  
15 methodology for calculating the IRD end-of-year true-up appears in GRSP II.C.3. *See* Power  
16 Rate Schedules and GRSPs, BP-26-A-01-AP01. Forecast credits for irrigation loads are  
17 calculated using an IRD that is derived by multiplying the irrigation loads identified in the  
18 CHWM contracts by the IRD rate. The IRD is described in Section 5.4.2. Forecast IRD  
19 credits for FY 2025-2028 are listed in Table 4 of this Study, line 8, and Power Rates Study  
20 Documentation, BP-26-FS-BPA-01A, Table 9.2, line 8.

21  
22 **9.1.1.5 Low Density Discount (LDD)**

23 The LDD is prescribed in § 7(d)(1) of the Northwest Power Act and offers a discount of up  
24 to 7 percent for customers that meet the criteria specified in the Power Rate Schedules and  
25 GRSPs, BP-26-A-01-AP01, GRSP II.B. 16 U.S.C. § 839e(d)(1). As set forth in the TRM, LDD  
26 percentages are calculated to provide a discount on power purchased at Tier 1 rates that

1 approximates the discount the customer would have received under non-tiered rates.

2 Forecast LDD credits for FY 2025-2028 are listed in Table 4 of this Study, line 9, and Power  
3 Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 9.

#### 4 5 **9.1.1.6 Tier 2 and Resource Support Services**

6 Tier 2 rates are based on a cost allocation that recovers the cost of BPA service to  
7 Above-RHWM Load. Tier 2 revenues are based on sales to customers that have elected to  
8 have BPA serve their Above-RHWM Loads. Forecast Tier 2 revenues for FY 2025-2028 are  
9 listed in Table 4 of this Study, line 10, and Power Rates Study Documentation, BP-26-FS-  
10 BPA-01A, Table 9.2, line 10.

11  
12 RSS revenues are based on known services chosen by customers. Forecast RSS revenues  
13 for FY 2025-2028 are listed in Table 4 of this Study, line 11, and Power Rates Study  
14 Documentation, BP-26-FS-BPA-01A, Table 9.2, line 11.

#### 15 16 **9.1.2 Industrial Firm Power Sales and New Resource Power Sales**

##### 17 **9.1.2.1 Industrial Firm Power Sales to Direct Service Industrial Customers**

18 BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the  
19 product of 1) forecast loads documented in Power Loads and Resources Study, BP-26-  
20 FS-BPA-03, Section 2.4, and accompanying Power Loads and Resources Documentation,  
21 BP-26-FS-BPA-03A, Tables 1.2.1 for energy, 1.2.2 for HLH, and 1.2.3 for LLH; and 2) the  
22 appropriate IP rate from RAM2026. For FY 2025, the revenues for DSI customers are  
23 calculated using the IP-24 rate. Forecast IP revenues for FY 2025-2028 are listed in Table 4  
24 of this Study, line 14, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2,  
25 line 14.

1 **9.1.2.2 New Resource Firm Power Sales**

2 The NR-26 rate applies to sales to investor-owned utilities under Northwest Power Act  
3 Section 5(b) requirements contracts. 16 U.S.C. § 839c(b). The NR-26 rate is also applicable  
4 to sales to any public body, cooperative, or federal agency to the extent such power is used  
5 to serve any NLSL, as defined by the Northwest Power Act, including planned NLSLs, as  
6 defined in Exhibit D of a customer’s CHWM contract. The NR-26 rate includes energy and  
7 demand rates. Forecast NR revenues for FY 2025-2028 are listed in Table 4 of this Study,  
8 line 13, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 13.

9  
10 **9.1.3 Products and Services under the FPS Rate**

11 During FY 2025-2028, BPA is providing power products and services under the FPS rate  
12 described in Section 4.4 of this Study. Revenues from the products and services are  
13 derived by multiplying individual customer billing determinants by the appropriate  
14 FPS rate. Forecast FPS revenues for FY 2025-2028 are listed in Table 4 of this Study,  
15 line 15, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 15.

16  
17 **9.1.4 Short-Term Market Sales**

18 The revenue forecast includes revenues from the sale of surplus energy, which can be a  
19 combination of secondary energy and firm energy in excess of that required to serve firm  
20 loads. The wholesale market price impacts various components in determining the  
21 forecast of surplus sales revenue. For FY 2025, the surplus energy revenue included in the  
22 revenue forecast consists of the average of the surplus energy revenues in forecast months  
23 computed during RevSim simulations of 40 iterations for each of 30 historical water years,  
24 for a total of 2,700 iterations. For FY 2025-2028, the surplus energy revenue is the median  
25 of the surplus energy revenues across those 2,700 iterations. In addition, BPA includes

1 a credit to account for the incremental value of marketing power to extra-regional PODs.  
2 See Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3.

3  
4 The revenue forecast for short-term market sales is computed using RevSim to calculate  
5 monthly HLH and LLH energy surpluses for each of the 2,700 iterations, applying  
6 corresponding market prices developed for each iteration. Additionally, the short-term  
7 market sales forecast contains revenue from contract sales for FY 2025-2028. The contract  
8 sales portion consists of DSI sales and sales outside the Pacific Northwest. See Power and  
9 Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3. Revenues for FY 2025-2028 are  
10 shown in Table 4 of this Study, line 16, and Power Rates Study Documentation, BP-26-  
11 FS-BPA-01A, Table 9.2, line 16.

### 13 **9.1.5 Long-Term Contractual Obligations**

14 Long-term obligation contracts include a wind energy exchange and capacity and energy  
15 exchanges. For FY 2025-2028, revenue from these contractual obligations is calculated  
16 pursuant to the individual contracts and then summed and added to the forecast as a  
17 group. BPA has long-term contracts to provide energy and capacity. Each contract is an  
18 advanced noticed right to power. See the Power and Transmission Risk Study, BP-26-  
19 FS-BPA-05, for more information. Forecast revenue for FY 2025-2028 is listed in Table 4 of  
20 this Study, line 17, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2,  
21 line 17.

### 23 **9.1.6 Canadian Entitlement Return**

24 The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the  
25 border pursuant to Columbia River Treaty between Canada and the U.S. No revenues are  
26 generated from the delivery of this power, but energy amounts are listed in the revenue

1 forecast to represent this system obligation. The average megawatt deliveries for FY 2025-  
2 2028 are listed in Table 4 of this Study, line 18, and Power Rates Study Documentation,  
3 BP-26-FS-BPA-01A, Table 9.2, line 18.

#### 4 **9.1.7 Other Sales**

6 Other Sales include forecast revenues from primarily the Slice True-Up and Load Shaping  
7 True-Up, which are applicable only for FY 2025. The forecast of Other Sales revenue for  
8 FY 2025-2028 is listed in Table 4 of this Study, line 19, and Power Rates Study  
9 Documentation, BP-26-FS-BPA-01A, Table 9.2, line 19.

### 11 **9.2 Revenue Forecast for Miscellaneous Revenues**

12 Miscellaneous Revenues include revenues from the Transfer Service Charges, Downstream  
13 Benefits, Reclamation power for irrigation, and the Upper Baker project.

15 The Transfer Service revenue forecast accounts for costs of the delivery of federal power  
16 over non-federal transmission systems and is described in Section 6 of this Study. Included  
17 in the Transfer Service revenue forecast are revenues from the Operating Reserve Charge,  
18 Regulation and Frequency Response Charge, and Regional Compliance Enforcement Charge  
19 as described in Sections 6.3-6.6.

21 Downstream Benefits are revenues BPA receives from utilities that benefit from the  
22 coordinated planning and operation of Corps and Reclamation upstream storage reservoirs  
23 as part of the Pacific Northwest Coordination Agreement. 62 Fed. Reg. 40,512 (July 7,  
24 1997). For FY 2025-2028, revenues from downstream benefits are estimated by applying a  
25 three-year average from the three most recent studies of downstream benefits conducted  
26 by the Northwest Power Pool (NWPP).

1 Reclamation power for irrigation includes power that has been reserved from the FCRPS  
2 for use at Reclamation projects. For revenue forecasting purposes, power that has been  
3 reserved for Reclamation irrigation projects is classified as either reserved power or  
4 irrigation pumping power. Revenue from reserved power for FY 2025-2028 is forecast in  
5 equal monthly amounts based on an annual amount that is aggregated for Reclamation  
6 projects. The annual aggregated amounts are forecast based on an average of actual results  
7 from the prior three years provided by Reclamation. Revenue from Irrigation Pumping  
8 Power for FY 2025-2028 is calculated using the same methodology as reserved power.

9  
10 Finally, revenues from the Upper Baker project are forecast. Puget Sound Energy keeps  
11 58,000 acre-feet of flood control at this reservoir, which must be held at a lower level  
12 during the winter than it would be without flood control, creating head losses. On behalf of  
13 the Corps, BPA compensates Puget by delivering non-firm energy and capacity during the  
14 flood control season of November through March. In turn, BPA offsets the value of energy  
15 and capacity delivered to Puget from the yearly U.S. Treasury payment, and the deduction  
16 is listed as a revenue receipt from the Corps.

17  
18 Miscellaneous revenues for FY 2025-2028 are listed in Table 4 of this Study, line 21, and  
19 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, lines 21-27.

### 21 **9.3 Revenue Forecast for Generation Inputs for Ancillary, Control Area, and** 22 **Other Services and Other Inter-Business Line Allocations**

23 Power Services receives revenue from Transmission Services for providing generation  
24 inputs for ancillary and control area services. Generation inputs cost allocations and the  
25 unit cost of balancing and operating capacity are described in detail below in Section 9.3.1.  
26 Revenue forecasts (inter-business line allocations) for Synchronous Condensing,

1 Generation Dropping, Redispatch, Segmentation of Corps and Reclamation network and  
2 delivery facilities costs, and Station Service costs are included in the Power Rates Study  
3 Documentation, BP-26-FS-BPA-01A, Tables 9.3.2-9.3.5.

4  
5 The revenues (inter-business line allocations) are shown in Table 4, line 22, of this Study  
6 and the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 48.

### 7 8 **9.3.1 Capacity Cost Methodology**

#### 9 **9.3.1.1 Introduction**

10 Various Ancillary and Control Area Services provided through BPA’s transmission rates  
11 require the use of generation capacity—specifically balancing and operating reserve  
12 services. All of this required capacity is sourced from the generating resources available to  
13 BPA and is considered a “generation input” into transmission rates. This section of the  
14 Study describes how the cost of this capacity is calculated.

15  
16 The Ancillary and Control Area Services that require the use of capacity are Regulation and  
17 Frequency Response Service, Balancing Services (VERBS and DERBS), and Operating  
18 Reserve Services (Spinning and Supplemental). Capacity required for Regulation and  
19 Frequency Response Service and the Balancing Services is further categorized as either  
20 Regulating or Non-Regulating Reserves. Both Regulating and Non-Regulating Reserves  
21 include *inc* capacity or *dec* capacity. Power Rates Study Documentation, BP-26-FS-  
22 BPA-01A, Table 9.3.1.7.

23  
24 The total cost of incremental capacity is calculated as the sum of two components: an  
25 embedded cost component and a variable cost component. The total cost of decremental  
26 capacity includes only a variable cost component. The embedded cost component accounts

1 for the fixed cost of the federal system. The variable cost component accounts for the lost  
2 efficiency (impact to available energy) associated with holding and deploying capacity. The  
3 calculation of the embedded costs is explained in detail in Section 9.3.1.2. The calculation  
4 of the variable costs is explained in detail in Section 9.3.1.3. The calculation of a rate design  
5 cost adjustment is explained in detail in Section 9.3.1.4. The calculation of total unit  
6 capacity costs and the associated revenue forecasts is described in Section 9.3.1.5.

7  
8 Once the unit cost of capacity is determined, the unit cost is multiplied by the forecast  
9 amount of capacity to be provided by Power Services and is treated as a revenue credit to  
10 power rates. Conversely, this amount is treated as a cost to Transmission Services. *See*  
11 *Transmission Revenue Requirement Study Documentation, BP-26-FS-BPA-09A, Table 3-5.*

### 13 **9.3.1.2 Embedded Cost Methodology**

14 BPA's embedded unit cost of capacity is calculated by dividing all of BPA's capacity costs by  
15 the amount of capacity available to BPA under monthly P10 firm generation from the  
16 30 water year set. BPA's capacity costs are determined using a capacity-and-energy-cost-  
17 classification methodology, where fixed costs are classified as capacity and variable costs  
18 are classified as energy. In general, this methodology associates the cost of building a plant  
19 with capacity, and the cost of fuel and other operational costs with energy, while also  
20 encompassing the broader set of costs that BPA pays and accounting for the fuel  
21 constraints and regulations associated with hydroelectric generation. The costs classified  
22 as capacity as a result of this method are: capital-related costs, Fish and Wildlife Program  
23 costs, a portion of power purchase costs, and two cost adjustments. The total amount of  
24 capacity available to BPA under monthly P10 water conditions is calculated as the sum of  
25 the monthly average one-hour capability of physical resources, any forecast or actual

1 augmentation purchase amounts, and all capacity reserved for Transmission Services for  
2 Ancillary and Control Area Services.

#### 3 4 **9.3.1.2.1 Capacity Cost Classification**

5 To calculate a capacity unit cost, BPA must first separate its revenue requirement into costs  
6 classified as capacity (fixed costs) and costs classified as energy (variable costs). For  
7 purposes of this calculation, fixed costs are defined as: 1) all capital-related costs, 2) costs  
8 that do not vary with resource output and are directly attributable to the generation  
9 capability of the resources available to BPA, and 3) the capacity-attributed portion of  
10 power purchase costs. For example, BPA's Fish and Wildlife Program costs are attributable  
11 to capacity because these costs are an obligation directly attributable to the resources  
12 available to BPA that do not vary with resource output. Costs that are not defined as fixed  
13 costs are considered variable costs. An example of an energy-attributable cost is BPA's  
14 staffing cost because these costs are not directly attributable to the generation capability of  
15 the resources available to BPA.

16  
17 Further, with only three exceptions, simplicity in the cost classification method is achieved  
18 by classifying 100 percent of each line item in the Cost of Service Analysis Disaggregated  
19 Costs and Credits table in RAM (*see* Power Rates Study Documentation, BP-26-FS-BPA-01A,  
20 Table 2.3.1.5) to either energy or capacity, with no split attributions. The first exception to  
21 this 100-percent-to-capacity or 100-percent-to-energy classification approach is in power  
22 purchases that provide both energy and capacity to BPA. The second exception is in the  
23 4(h)(10)(C) credit where the credit is tied to specific costs. The third exception is  
24 Synchronous Condensing where a portion of the costs of providing this service is  
25 associated with plant investment (capacity) and the other portion associated with energy.  
26 Each of these adjustments are described below. The net cost attributed to capacity for the

1 rate period is \$1,269.7 million per year. Power Rates Study Documentation, BP-26-  
2 FS-BPA-01A, Table 9.3.1.3, line 24.

### 3 4 **Capital-Related Costs**

5 As stated above, all capital-related costs are classified as capacity costs. Capital-related  
6 costs include depreciation, amortization, interest expense, decommissioning costs, and  
7 minimum required net revenues. Capital-related costs average \$902.4 million for the rate  
8 period. *Id.*, line 7.

### 9 10 **Fish and Wildlife Costs**

11 In addition to capital-related costs, fixed costs include costs that do not vary with resource  
12 output and are directly attributable to the generation capability of the resources available  
13 to BPA. The only costs that fit this definition are BPA's Fish and Wildlife Program costs. In  
14 addition to direct BPA fish and wildlife costs, BPA pays U.S. Fish and Wildlife Service  
15 program costs associated with the Lower Snake River Hatcheries and pays the Northwest  
16 Power and Conservation Council (NPCC) to help finance its Fish and Wildlife Program  
17 (50 percent of BPA's payments to NPCC go toward fish and wildlife and the other  
18 50 percent goes toward conservation). The total of all directly attributable fish and wildlife  
19 costs average \$368.9 million per year for the rate period. *Id.*, line 12.

### 20 21 **Power Purchase Costs**

22 Power purchase costs are included in the embedded cost of capacity calculation if they are  
23 flat annual blocks of power, such as system augmentation, or if they are the purchase of the  
24 output from a dispatchable resource. Power purchases from variable resources, such as  
25 wind and solar output, are attributed entirely to energy and are not relied upon for  
26 capacity. Power purchase costs are included because they increase the capacity available

1 to BPA but are not captured by the inclusion of capital-related or fish and wildlife costs.  
2 Unlike BPA's physical resources—where a capacity-and-energy-cost-classification  
3 methodology can be used—the cost of power purchases often includes a single dollars-per-  
4 megawatthour cost only, with no visibility into the capacity and energy cost components.  
5 In these situations, a ratio of maximum-output to maximum-output-plus-average-  
6 generation is used to classify the portion of the total cost that is attributable to capacity.

7  
8 For a flat annual block of power, this method attributes 50 percent of the cost to energy  
9 and the other 50 percent to capacity. This is because, for a flat block of power, the  
10 maximum generation and average generation are the same. For Clearwater Hatchery  
11 Generation, which is the only physical hydro resource that BPA currently pays for the  
12 output in a single dollars-per-megawatthour cost, this method attributes 39.5 percent to  
13 energy and 60.5 percent to capacity. The total rate period average of power purchase costs  
14 classified as capacity costs for purposes of calculating BPA's unit cost of capacity is  
15 \$83.4 million per year. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
16 Table 9.3.1.3., line 18.

### 18 **Cost Adjustments**

19 Two cost adjustments are made to the total embedded costs, one for the 4(h)(10)(C) credit  
20 and another for Synchronous Condensing. The portion of the 4(h)(10)(C) credit that is  
21 associated with program costs is included because Fish and Wildlife Program costs are  
22 included in the capacity cost calculation, and a portion of 4(h)(10)(C) credit is an offset to  
23 those costs. The portion of the 4(h)(10)(C) credit that is associated with the cost of  
24 balancing purchases is excluded because the cost of balancing purchases is classified as an  
25 energy cost. The portion of BPA's capacity costs that are allocated to Synchronous  
26 Condensing—the investments in plant modifications at the John Day and The Dalles

1 projects that are necessary to provide Synchronous Condensing—are removed (\$189,000  
2 per year) to avoid double counting, since these capacity costs are associated with  
3 Synchronous Condensing and are already assigned to Transmission through that  
4 methodology, as described in Section 9.3.2 of this Study. *Id.*, line 22. The portion of the  
5 4(h)(10)(C) credit associated with capacity and the removal of the costs associated with  
6 Synchronous Condensing totals an average of \$84.9 million per year for the rate period.  
7 *Id.*, line 23.

### 9 **Treatment of Conservation**

10 All costs associated with conservation are excluded from the calculation of the embedded  
11 capacity cost. This is because, although energy conservation provides both capacity and  
12 energy benefits, the amount of capacity provided from BPA’s conservation investments is  
13 not readily available. Given this, both the costs of conservation and conservation’s  
14 contribution to the system capability of the resources available to BPA are excluded.

#### 16 **9.3.1.2.2 The Capacity Available to BPA**

17 The capacity of all the resources available to BPA, excluding conservation (*see* Section  
18 9.3.1.2.1 above), is made up of 1) physical resources (regulated hydro, independent hydro,  
19 small hydro, and thermal); and 2) forecast or actual generation augmentation purchases.  
20 Non-hydro renewable generation, described in detail in the Power Loads and Resources  
21 Study, BP-26-FS-BPA-03, § 3.1.3, is excluded. Although these wind and solar resources  
22 produce energy, they are excluded from capacity because these forms of generation are  
23 variable. The sum of these two sources is equal to an annual average one-hour system  
24 capability (under monthly P10 firm generating conditions) of 16,571 MW for the rate  
25 period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.2, line 33.

1 **Capacity from Physical Resources**

2 BPA's primary source of capacity is from physical resources and is equal to 16,295 MW.  
3 Physical resource capacity is established as described in the Power Loads and Resources  
4 Study, BP-26-FS-BPA-03, § 3.1.2. The 14-period one-hour capacity of each federal resource  
5 type is averaged to create an annual average one-hour capacity under monthly P10 firm  
6 generating conditions. These average annual one-hour capacities are then averaged across  
7 the three-year rate period, and reduced for transmission losses, to create rate period  
8 average one-hour capacities after losses. *See* Power Rates Study Documentation, BP-26-  
9 FS-BPA-01A, Table 9.3.1.2.

10  
11 **Capacity from Power Purchases**

12 BPA may also obtain additional capacity through forecast and actual power purchases.  
13 All forecast and actual power purchase amounts considered augmentation purchases are  
14 included in the total amount of capacity available to BPA. System augmentation is  
15 discussed in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 4.2, and System  
16 augmentation amounts are presented in that Study in Table 2. All augmentation purchases,  
17 including Tier 1, Tier 2 and Other Augmentation, are assumed to be made on a flat annual  
18 basis. These flat augmentation purchases increase the amount of capacity available to the  
19 federal system by an equal amount in all months. *See* Power Rates Study Documentation  
20 BP-26-FS-BPA-01A, Table 9.3.1.2, lines 31-32.

21  
22 **9.3.1.2.3 Embedded Unit Cost Calculation**

23 The embedded unit cost of capacity is calculated by taking the costs attributable to capacity  
24 (*see* Section 9.3.1.2.1) and dividing by the capacity of the resources available to BPA. The  
25 embedded unit cost of capacity is equal to \$6.39/kW per month. Power Rates Study  
26 Documentation, BP-26-FS-BPA-01A, Table 9.3.1.4, line 8.

1 **9.3.1.3 Variable Cost Pricing Methodology**

2 **9.3.1.3.1 Introduction and Purpose**

3 When BPA holds reserve capacity, it incurs variable costs due to efficiency losses. To hold  
4 reserves on stand-by, BPA incurs fuel costs as water is used in a manner less efficient than  
5 had BPA not been required to hold reserves. Efficiency losses impact the federal system in  
6 regard to output in MWhs, timing of energy generation, and therefore net revenues  
7 received from sales. The Variable Fuel Cost Model (VFCM) calculates the variable costs of  
8 holding reserves on the federal system for the duration of the rate period.

9  
10 The changes in efficiency are determined by conducting an “A B” test in which two  
11 scenarios are compared. The A case is a scenario in which all required reserves are held  
12 and modeled. The B case is a hypothetical scenario in which a reserve constraint is relaxed.  
13 The delta between the generation levels of these two cases are priced to determine the  
14 efficiency costs of holding reserves. Two types of costs are calculated in the model. First,  
15 energy shift costs are the costs associated with the change in daily generation shape due to  
16 holding reserves. Second, net generation delta costs are associated with the overall change  
17 in available daily generation due to holding reserves.

18  
19 **9.3.1.3.2 Inputs**

20 This section describes the preparation of the input data for the VFCM.

21  
22 **RiverWare System Generation Forecast**

23 The VFCM uses the hourly total system generation values for each case used in the A B test.  
24 See Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.4, as well as the BPA  
25 2024 White Book for additional information on how the RiverWare application is used for  
26 system planning.

1 The RiverWare model simulates the operation of the FCRPS and produces a measure of  
2 aggregated system generation for each hour, day, month, and rate period year assuming  
3 hydrological conditions for each year of a representative 30-year sample. The sample  
4 water years are 1989 to 2018. The model simulates the generation levels given system  
5 constraints, including reservoir targets, flood control, and fish passage.

6  
7 These hourly generation values are used in combination with prices produced by the  
8 Aurora production cost model. The Aurora Market Price Forecast is discussed more below.

9  
10 In order to perform the A B test, but separate the impact of *inc* versus *dec* reserves, three  
11 scenarios were run through the RiverWare model: Base, *Inc* Reserves, and *Dec* Reserves.

- 12 1. The first scenario is classified as the Base Case. This is the case where *inc*  
13 and *dec* reserves are assumed to be held in the RiverWare modeled run. In  
14 other words, in this scenario, total generation measures include all assumed  
15 reserve constraints.
- 16 2. The second scenario is classified as *Inc* Reserves. This is the case where the  
17 constraint to hold *inc* reserves is removed from the RiverWare modeled run.  
18 All other constraints from the base case remain. The capacity quantities that  
19 are counted in this scenario are quantities necessary for Regulating *inc*  
20 balancing reserves as well as operating reserves (spinning and  
21 supplemental).
- 22 3. The third scenario is classified as *Dec* Reserves. This is the case where the  
23 constraint to hold *dec* Reserves is removed from the RiverWare modeled run.  
24 All other constraints from the base case remain. The capacity quantities that  
25 are counted in this scenario are quantities necessary for Regulating *dec*  
26 balancing reserves.

## **Aurora Market Price Forecast**

Another input into the VFCM is the Mid-Columbia (Mid-C) Aurora market price forecast. See Power Market Price Study, BP-26-FS-BPA-04, Section 2.4. The Aurora market price forecast applies variability to several inputs (such as loads, natural gas market prices, transmission system constraints, and long-term resource build assumptions across the WECC) to simulate 90 iterations for each year of the 30 water samples to produce a total of 2,700 iterations from which to compute average monthly diurnal prices at the Mid-C hub. The 90 iterations for each water year are averaged across months, or monthly diurnal periods, to produce a set of flat monthly prices, and a set of flat monthly diurnal prices, for each water year.

### **9.3.1.3.3 Pre-calculation data processing**

#### **Generation Delta Using RiverWare**

The generation delta is measured as the difference between the Case B generation levels where reserve constraints have been relaxed (“Unconstrained Gen”) and the Case A generation level (“Base Case Gen”) for each hour (H) in a day. The following equation summarizes this calculation:

$$Generation\ Delta_H = Unconstrained\ Gen_H - Base\ Case\ Gen_H$$

Positive generation deltas indicate that for each given hour the unconstrained case simulates higher levels of generation than the constrained case. The reverse is true for negative generation deltas; for each given hour the unconstrained case simulates lower levels of generation than the constrained case.

To mitigate the potential for biased results, the total generation delta was adjusted to exclude outliers by removing observations below the 5th percentile and above the 95th

1 percentile for each month and water year. Unique months within each water year that had  
2 less than five standard deviations were deemed to have no outliers and therefore did not  
3 have any observations excluded.

4  
5 The total sum of hourly generation deltas for a day is split into two separate cost  
6 components that consist of energy shift and net generation delta, as described below.

### 8 **Energy Shift**

9 In the VFCM, energy shift is the term used to describe the measured losses of system  
10 flexibility because of the need to hold reserves. Flexibility allows system operators to  
11 engage in load factoring which is a process in which water is saved in one period in order  
12 to use it during a later high load or high value period. An example of load factoring is when  
13 operators minimize generation during low load periods such as the early morning (*e.g.*,  
14 3 a.m.) in order to save water for high load periods later in the day such as the evening (*e.g.*,  
15 4-8 p.m.). Load factoring does not necessarily occur in equal time periods. For example,  
16 load factoring may be conducted by saving water during a concentrated period (two or  
17 three hours) and then using that water over a longer period (five to seven hours). Energy  
18 shifts are measured in megawatthours on a daily basis and reflect the changing dynamics of  
19 hydro conditions as well as seasonal load variations. This means that load factoring looks  
20 different in different parts of the year. Because RiverWare produces hourly generation  
21 data for the rate period, the model captures the energy shifts that are unique to each day of  
22 simulated generation.

23  
24 As modeled by the VFC, energy shifts are energy neutral within a day in that they do not  
25 result in any more or less MWh in the given day. The losses are associated with shifting a  
26 given amount of energy from an opportune period to a less opportune period.

1 The VFCM calculates the MWh of energy shift for each water year and day by selecting the  
2 smaller absolute value of either 1) the total hourly sum of negative generation deltas for  
3 each day, or 2) the total hourly sum of positive generation deltas for each day. This is  
4 calculated for both the *inc* scenario as well as the *dec* scenario. In this way, energy shifts  
5 are modeled as energy neutral for a given day, and the model is designed to establish the  
6 daily quantity of megawatthours of either positive or negative generation deltas as a  
7 quantity of shifted energy. The following equation summarizes this calculation:

$$8 \quad \text{Energy Shift Delta} = \min \left( \left| \sum_{H=1}^{24} \text{Negative Delta}_H \right|, \left| \sum_{H=1}^{24} \text{Positive Delta}_H \right| \right)$$

10 *where:*

11 *Negative Delta<sub>H</sub> is Generation Delta<sub>H</sub> < 0, and*

12 *Positive Delta<sub>H</sub> is Generation Delta<sub>H</sub> > 0.*

### 13 **Net Gen Delta**

14 The daily net generation delta represents the sum daily megawatthour impacts of holding  
15 reserves after energy shifts have been accounted for. These are the impacts that are not  
16 energy neutral over the course of a day within each water year. Some key factors that are  
17 estimated in the net generation delta are forced spill and changes in system efficiency.

18 Because the VFCM uses RiverWare simulation data for the whole system, the impacts of  
19 holding reserves are not isolated for particular projects within the FCRPS or particular  
20 types of impacts. Net generation deltas are typically a positive value, but for some days  
21 they can be negative. A positive net generation delta represents a situation in which  
22 holding reserves results in lower levels of generation for a given day. Appearing less  
23 frequently, negative net generation deltas represent a situation in which holding reserves  
24 results in higher levels of generation for a given day.

1 Daily Net Generation Deltas are calculated by summing the hourly generation deltas for a  
2 single day in each of the water years. The generation deltas that offset each other  
3 throughout the day are considered energy shift and the remaining generation deltas are  
4 summed as the net generation delta for each day. The following equation summarizes this  
5 calculation:

$$6 \qquad \qquad \qquad \text{Net Generation Delta} = \sum_{H=1}^{24} \text{Delta}_H$$

### 9 **Aurora Mid-C Market Price Forecast**

10 The VFCM utilizes two price sets from the Mid-C Aurora forecast. The first is the monthly  
11 flat price forecast. This price set is averaged across iterations for each water year, fiscal  
12 year, and month. The second price set is the LLH/HLH price set. This price set is also  
13 averaged across iterations for each condition, LLH and HLH. The monthly flat price for  
14 each water year is used as-is without further adjustments. The VFCM adapts a month's LLH  
15 and HLH into a high and low price set by taking the maximum and minimum value from  
16 each month's HLH and LLH price set.

#### 18 **9.3.1.3.4 Calculation of Reserve Costs**

19 The total variable reserve cost is the sum of the energy shift costs and the net generation  
20 delta costs. For each water year and day, energy shift costs are calculated by multiplying  
21 the quantity of shifted energy (megawatthours) by the price spread between the high and  
22 low price for the matching water year and month. The price spread is calculated by  
23 subtracting the low price from the high price for each water year and month. The logic  
24 behind pricing energy shift in this manner is that the price spread signifies the costs to hold  
25 reserves. For example, if the requirement to hold reserves results in over-generation in  
26 particular periods, and under-generation in other periods it is assumed that the periods of

1 forced over-generation are during periods of lower prices and times of forced under-  
2 generation are during periods of higher prices. The net result of the modeled forced sale  
3 (over-generation or negative generation deltas) and foregone sale/forced purchase (under-  
4 generation or positive generation deltas) is calculated by multiplying the sum of daily  
5 energy shift MWh (for each water year) by each water year's monthly price spread. The  
6 daily total costs are then averaged across the 30 water years before summing those daily  
7 values to create monthly totals.

8  
9 The net generation delta cost for each water year and day is calculated by multiplying the  
10 quantity of net generation delta (megawatthours) by the monthly average price for each  
11 water year. The logic follows that the overall change in system efficiency as measured by  
12 total generation cannot be associated with any particular period within each day and thus  
13 it is appropriate to assume the monthly average price rather than a price associated with a  
14 monthly high or low price or particular diurnal time frame such as HLH and LLH. After  
15 daily total costs are calculated, they are averaged across the 30 water years before  
16 summing those for each month within the rate period.

17  
18 Once each component part is calculated the total monthly variable reserve cost is  
19 calculated by summing the monthly energy shift cost and the monthly net generation cost.  
20 A sum of each month per fiscal year produces an annual total variable fuel cost of reserves.

1 The following equations summarize the calculations described above:

$$\begin{aligned} & \text{Energy Shift Delta Cost}_M \\ & = \text{Energy Shift Delta}_M \times (\text{High Price}_M - \text{Low Price}_M) \end{aligned}$$

$$\text{Net Generation Delta Cost}_M = \text{Net Generation Delta}_M \times \text{Average Price}_M$$

$$\begin{aligned} & \text{Total Variable Fuel Costs}_M \\ & = \text{Energy Shift Delta Cost}_M + \text{Net Generation Delta Cost}_M \end{aligned}$$

$$\text{Total Annual Variable Fuel Costs} = \sum_{M=1}^{12} \text{Total Variable Fuel Costs}_M$$

### 13 **9.3.1.3.5 Variable Cost of Reserves**

14 The purpose of the VFCM is to determine the costs associated with holding reserves on the  
15 FCRPS system. These costs are attributed to two categories of reserves, *inc* and *dec*. For  
16 simplicity, the VFCM does not account for potential further subcategorization such as  
17 spinning versus non-spinning *inc* reserve capacity. (Accounting for the differences in the  
18 types of *inc* and *dec* reserves is applied in the rate design step described below in  
19 Section 9.3.1.4 below.) While costs are calculated for *inc* and *dec* in aggregate, the model  
20 does, however, differentiate between costs that are incurred due to energy shifts and  
21 general net changes in generation. The output from the VFCM thus includes information  
22 for each of these categories of costs that are incurred due to holding reserves.

23  
24 The VFCM was calculated for the Initial Proposal, using quantities that were part of the  
25 forecast at that time. The results of the VFCM analysis completed for the Initial Proposal

1 have been applied to here for the Final Proposal. For the BP-26 rate period, the VFCM  
2 measures the costs associated with 1,111 MW of *inc* Reserves and 609 MW of *dec* Reserves.  
3 These values include the assumption that the FCRPS reaches its maximum threshold of  
4 900 MW *inc* and 1,100 MW *dec* for balancing reserves as described in the Generation Inputs  
5 Study, BP-26-FS-BPA-06, § 2.10. For the *inc*, 578 MW of the total is associated with  
6 Regulation Balancing Reserves and the remaining, 533 MW, is associated with Operating  
7 Reserves. For *dec*, the entire 609 MW is associated with Regulation Balancing Reserves.  
8 Non-Regulating Balancing Reserves, both *inc* and *dec*, were excluded from the VFCM  
9 because BPA has an opportunity to recoup the costs associated with holding Non-  
10 Regulating Balancing Reserves through its participation in the Western EIM.

11  
12 Total variable costs associated with *inc* and *dec* are provided by month in Power Rates  
13 Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.5. For the BP-26 rate period, the  
14 annual average associated with *dec* is \$1.3 million and with *inc* is \$14.5 million. Power  
15 Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.5, line 38.

#### 16 17 **9.3.1.4 Rate Design Cost Adjustment Methodology**

18 After embedded and variable costs have been calculated and before final reserve capacity  
19 rates are established, a rate design step is applied to incremental capacity reserves to  
20 reflect the relative opportunity costs associated with providing different types of  
21 capacity—fast and flexible capacity as compared to slower and less flexible capacity. The  
22 value delta is equal to the difference in costs between thermal generators designed for each  
23 type of reserve capacity type. The outcome of this benchmarking process illustrates that  
24 faster and more flexible capacity is more costly than slower and less flexible capacity. The  
25 process by which BPA applies the value delta to Regulating and Non-Regulating *inc*

1 balancing reserves and spinning and supplemental operating reserves is detailed in  
2 Section 9.3.1.5.1 below.

#### 4 **9.3.1.4.1 Fast and Flexible vs. Slower and Less Flexible Incremental Benchmarking**

5 Measuring the cost differential between fast and flexible versus slower and less flexible  
6 reserves begins by selecting benchmarking generators that are appropriate for providing  
7 each type of *inc* service. The Wärtsilä 18V50SG reciprocating generator is selected to  
8 benchmark costs associated with providing fast and flexible reserve services and the  
9 General Electric 7HA.02 combustion turbine is selected for providing slower and less  
10 flexible services. The Wärtsilä reciprocating generator (RG) is used to benchmark  
11 Regulating and spinning operating reserves due to its technical capability to provide fast  
12 and flexible reserve capacity. The 7HA.02 turbine, on the other hand, is a standard in  
13 providing slower and less flexible capacity due to its fuel efficiency and lower long-term  
14 costs. The 7HA.02 turbine is used to benchmark Non-Regulating and supplemental  
15 operating reserves.

16  
17 Benchmarking is conducted by calculating the annual average expense to own, operate and  
18 maintain the Wärtsilä RG and the 7HA.02 combustion turbine (CT). A detailed description  
19 of how annual fixed costs associated with the Wärtsilä RG are calculated is available in  
20 Section 4.1.1.2.1 above and shown in Power Rates Study Documentation, BP-26-FS-  
21 BPA-01A, Table 4.1. The same process is applied to the 7HA.02 CT to determine the  
22 annual average expense to own, operate and maintain the generator. Power Rates Study  
23 Documentation, BP-26-FS-BPA-01A, Table 9.3.1.6. The annual average expense is divided  
24 by 12 to calculate the monthly average cost to operate each generator. The average dollars  
25 per kilowatt per month costs for the Wärtsilä RG and 7HA.02 CT are compared to derive

1 the cost differential. This cost differential is used to create the value delta between the  
2 spinning and non-spinning *inc* reserve capacity.

3  
4 For FYs 2026-2028, the estimated average cost for the Wärtsilä RG is \$11.70/kW/month  
5 and for the 7HA.02 CT is \$7.04/kW/month. Power Rates Study Documentation, BP-26-  
6 FS-BPA-01A, Table 4.1, line 26, column J, and Table 9.3.1.6, line 14. The value delta for  
7 FYs 2026-2028 is thus \$4.66/kW/month. Power Rates Study Documentation, BP-26-  
8 FS-BPA-01A, Table 9.3.1.6, line 26, column J.

### 9 10 **9.3.1.5 Capacity Cost Calculation**

#### 11 **9.3.1.5.1 Unit Cost by Reserve Type**

12 The variable costs allocated to *inc* balancing, *dec* balancing, and operating reserves are  
13 divided by their respective quantities of capacity to calculate a unit cost of the allocated  
14 variable costs. As discussed above, the VFCM calculates costs associated with the  
15 Regulating portion of the *inc* balancing reserve requirement; however, those variable unit  
16 costs are allocated into a general *inc* balancing reserve cost bucket due to the fact that they  
17 are differentiated in a later rate design step that is described below. The unit cost for Non-  
18 Regulating *dec* reserves has no allocated variable costs. The variable unit costs for each  
19 type of capacity are as follows:

- 20 • For *inc* balancing the unit cost of allocated variable costs is \$0.87/kW/month.
- 21 • For Regulating *dec* balancing the unit cost of allocated variable costs is  
22 \$0.21/kW/month.
- 23 • For Non-Regulating *dec* balancing the unit cost of allocated variable costs is  
24 \$0.00/kW/month.
- 25 • For operating reserves the unit cost of allocated variable costs is \$0.87/kW/month.

1 The embedded unit cost of \$6.39/kW/month (Power Rates Study Documentation, BP-26-  
2 FS-BPA-01A, Table 9.3.1.9, line 2) is added to the unit cost of allocated variable costs for *inc*  
3 balancing and operating reserves. The unit cost for *dec* reserves has no embedded cost  
4 component. The total unit costs of allocated embedded and variable costs for each type of  
5 capacity are as follows:

- 6 • The total unit cost for *inc* balancing is \$7.26/kW/month (*id.*, lines 12, 14).
- 7 • The total unit cost for Regulating *dec* balancing is \$0.21/kW/month (*id.*, line 13).
- 8 • The total unit cost for Non-Regulating *dec* balancing is \$0.00/kW/month (*id.*,  
9 line 15).
- 10 • The total unit cost for operating reserves is \$7.26/kW/month (*id.*, line 16).

11  
12 Once the total unit cost is determined, a rate design step is applied to create a price  
13 differential between Regulating and Non-Regulating *inc* balancing reserves as well as  
14 between spinning and supplemental operating reserves to reflect the differing opportunity  
15 costs (*i.e.*, the value delta as described above) associated with providing these capacity  
16 types. The goal of this step is to establish a fixed price delta between unit costs of faster  
17 services and slower services without collecting more revenue than the amount of costs  
18 allocated to each service prior to applying the rate design step.

19  
20 Costs of the BPA's available capacity are allocated to each service (Non-Regulating and  
21 Regulating, spinning and supplemental) in proportions equal to the overall balancing area  
22 needs. These are the proportions that reflect the required reserve capacity established by  
23 the BAA irrespective of the supplier of that reserve capacity. BPA's application of a rate  
24 design through a fixed value delta looks to these proportions to establish suitable price  
25 signals that incent efficient decisions concerning supply alternatives. Power Rates Study  
26 Documentation, BP-26-FS-BPA-01A, Tables 9.3.1.7 and 9.3.1.8. The proportions used for

1 this cost allocation were established in the Initial Proposal. These same proportions are  
2 applied here.

3  
4 The process of applying the rate design step begins with the total allocated costs  
5 (embedded and variable) of each service along with the total MW quantities forecasted for  
6 the two capacity types within each service (Regulating and Non-Regulating for the  
7 balancing service and spinning and supplemental for the operating reserve service).  
8 The following set of two equations are then applied to calculate the cost of the two  
9 balancing reserves types (Regulating and Non-Regulating):

10  
11 *Balancing inc Reserves*

$$12 \quad UC_R - UC_{NR} = VD$$

$$13 \quad UC_R(MW_R) + UC_{NR}(MW_{NR}) = TotalAllocatedCost_{Bal\_Inc}$$

14  
15 *Where:*

16  $UC_R$  refers to the unit cost for Regulating *inc* reserves.

17  $UC_{NR}$  refers to the unit cost for Non-Regulating *inc* reserves.

18  $VD$  refers to the Value Delta (*i.e.*, the opportunity cost rate design goal), as described  
19 in Section 9.3.1.4.1 above, and is equal to \$4.66/kW/month.

20  $MW_R$  refers to the quantity of regulation *inc* reserves.

21  $MW_{NR}$  refers to the quantity of Non-Regulating *inc* reserves.

22  $TotalAllocatedCost_{Bal\_Inc}$  refers to the total costs allocated to *inc* balancing  
23 services.

24  
25 The average annual Regulating balancing *inc* reserves forecasted for the rate period is  
26 434,000 kW and Non-Regulating balancing *inc* reserves are 404,000 kW. Power Rates

1 Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.8, lines 3, 4. The average annual  
2 amount of costs allocated to Regulating and Non-Regulating balancing *inc* is \$73.0 million.  
3 *Id.*, line 6. Given this information, the Regulating balancing *inc* service receives a value  
4 adjustment of +\$2.25/kW/month and Non-Regulating balancing *inc* service receives  
5 a value adjustment of -\$2.41/kW/month. *Id.*, Table 9.3.1.9, lines 21-22. After the rate  
6 design step is applied, the unit cost for Regulating *inc* balancing capacity is  
7 \$9.51/kW/month, and the unit cost for Non-Regulating *inc* balancing capacity  
8 \$4.85/kW/month. *Id.*, lines 27, 29.

9  
10 The following set of two equations are applied to calculate the cost of the two operating  
11 reserves types (spinning and supplemental):

12  
13 *Operating inc Reserves*

$$14 \quad UC_{Spin} - UC_{Sup} = VD$$

$$15 \quad UC_{Spin}(MW_{Spin}) + UC_{Sup}(MW_{Sup}) = TotalAllocatedCost_{OP}$$

16  
17 *Where:*

18  $UC_{Spin}$  refers to the unit cost for spinning operating reserves.

19  $UC_{Sup}$  refers to the unit cost for supplemental operating reserves.

20  $VD$  refers to the Value Delta (*i.e.*, the opportunity cost rate design goal) as described  
21 in Section 9.3.1.4.1 above and is equal to \$4.66/kW/month.

22  $MW_{Spin}$  refers to the quantity of operating spinning reserves.

23  $MW_{Sup}$  refers to the quantity of operating supplemental reserves.

24  $TotalAllocatedCost_{OP}$  refers to the total costs allocated to operating reserves  
25 service.

1 The average annual operating reserves forecasted for this rate period are 504,000 kW, half  
2 of which are spinning and half of which are supplemental. Power Rates Study  
3 Documentation, BP-26-FS-BPA-01A, Table 9.3.1.8, lines 11-12. The average annual amount  
4 of costs allocated to operating reserves is \$43,949. *Id.*, line 14. Given this information,  
5 spinning operating reserves receives a value adjustment of +\$2.33/kW/month and  
6 supplemental operating reserves an adjustment of -\$2.33/kW/month. *Id.*, Table 9.3.1.9,  
7 lines 23-24. After the rate design step is applied, the unit cost is \$9.59/kW/month for  
8 spinning operating reserves capacity and \$4.93/kW/month for supplemental operating  
9 reserves capacity. *Id.*, lines 31-32.

#### 11 **9.3.1.5.2 Forecast of Revenue from Balancing Reserves**

12 The revenue from providing Regulating reserves is forecast by applying the unit costs to  
13 the Regulating reserves *inc* and *dec* quantity forecasted to be purchased by Transmission.  
14 Transmission has forecasted the purchase of an average of 482,000 kW (annual average) of  
15 Regulating reserves *inc*, and 503,00 kW (annual average) of Regulating reserves *dec*.  
16 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.10, lines 14, 15. These  
17 quantities do not include quantities necessary to provide balancing services for federal  
18 generation. The revenue forecast is an average annual amount of \$56.3 million. *Id.*,  
19 lines 21-22.

21 The revenue from providing Non-Regulating Reserves is forecast by applying the unit costs  
22 to the Non-Regulating Reserves *inc* and *dec* quantity forecasted to be purchased by  
23 Transmission. Transmission has forecasted the purchase of an average of 334,000 kW  
24 (annual average) of Non-Regulating Reserves *inc*, and 466,000 kW (annual average) of  
25 Non-Regulating Reserves *dec*. *Id.*, lines 16, 17. These quantities do not include quantities

1 necessary to provide balancing services for federal generation. The revenue forecast is an  
2 average annual amount of \$19.4 million. *Id.*, lines 23-24.

### 4 **9.3.1.5.3 Forecast of Revenue from Operating Reserves**

5 The revenue from providing spinning operating reserves is forecast by applying the unit  
6 cost calculated above to the spinning operating reserves quantity forecast. The revenue  
7 forecast is an average annual amount of \$29.0 million. *Id.*, line 27.

8  
9 The revenue from providing non spinning operating reserve is forecast by applying the unit  
10 cost calculated above to the non spinning operating reserve quantity forecast. The revenue  
11 forecast is an average annual amount of \$14.9 million. *Id.*, line 28.

## 13 **9.3.2 Synchronous Condensing**

### 14 **9.3.2.1 Introduction**

15 This section describes the method used to determine the amount of energy consumed by  
16 those FCRPS hydro generators that operate as synchronous condensers, and the  
17 determination of the cost of that energy that is allocated to BPA Transmission Services. It  
18 also describes the costs allocated to Transmission Services associated with the investment  
19 in plant modifications necessary to provide synchronous condensing at the John Day and  
20 The Dalles projects. Synchronous condensing costs allocated to Transmission Services are  
21 recovered through transmission rates and passed to BPA Power Services as an inter-  
22 business-line transfer.

### 24 **9.3.2.2 Description of Synchronous Condensers**

25 A synchronous condenser is essentially a motor with a control system that enables the unit  
26 to regulate voltage. These machines dynamically absorb or supply reactive power as

1 necessary to maintain voltage as needed by the transmission system. Some FCRPS  
2 generators operate in synchronous condenser or “condense” mode for voltage control and  
3 for other purposes (*i.e.*, to accommodate operational constraints associated with taking a  
4 unit offline). A generator operating in condense mode provides the same voltage control  
5 function as the unit does when generating real power. As with any motor, a unit operating  
6 in condense mode consumes real energy. Generators operating in condense mode in the  
7 FCRPS consume energy supplied by other units in the FCRPS.

### 9 **9.3.2.3 Synchronous Condenser Costs**

10 Synchronous condensing costs include the cost of 1) investment in plant modification at  
11 John Day and The Dalles projects necessary to provide synchronous condensing, and  
12 2) energy consumed by FCRPS generators while operating in condense mode for voltage  
13 control.

14  
15 The investments in plant modifications at the John Day and The Dalles projects result in an  
16 average cost of \$189,333 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
17 Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-26-FS-  
18 BPA-02A, Table 2F. These costs are the annual capital-related costs in the power revenue  
19 requirement associated with the investment that Power Services made in the plants at the  
20 request of Transmission Services to enable synchronous condense capability.

21  
22 For the costs associated with the energy used in condense mode operations, the amount of  
23 forecast energy is priced at an average annual market price. The methodology to  
24 determine the amount and cost of energy consumption is described below.

1 **9.3.2.4 General Methodology to Determine Energy Consumption**

2 For the FY 2026-2028 rate period, the FCRPS generators capable of operating in condense  
3 mode are identified, and the number of hours that the generators would operate in  
4 condense mode for voltage control is forecast. The forecast is derived from historical  
5 synchronous condenser operations, based on an average of the following three years of  
6 data, which are fiscal years 2021, 2022, and 2023. The average number of hours is  
7 multiplied by the fixed hourly energy consumption for the generators to determine the  
8 amount of energy consumed. The fixed hourly energy consumption is the motoring power  
9 consumption of the specific generator units when they are operated in condense mode.  
10 *See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1.*

11  
12 Finally, the market price forecast is applied to the amount of energy consumed to calculate  
13 the cost of synchronous condensing. The methodology for assigning historical  
14 synchronous condenser operations to the voltage control function and calculating the  
15 associated energy use for each of the FCRPS projects capable of operating in condense  
16 mode is described below.

17  
18 **9.3.2.4.1 Grand Coulee Project**

19 Six generators (Units 19-24) at the Grand Coulee project are capable of operating as  
20 synchronous condensers, although only three are typically operated in condense mode.  
21 The Study forecasts the number of hours that the Grand Coulee units will operate in  
22 condense mode based on historical condenser operations for the three-year historical  
23 period. The transmission system typically needs additional voltage control from the Grand  
24 Coulee project during nighttime hours (generally hours 20:00 to 06:00), when the lightly  
25 loaded transmission system results in excess reactive power and causes excess voltage on  
26 the system. Historical reactive demand and unit operations are examined, and units

1 operated in condense mode are allocated to either Transmission Services or Power  
2 Services, based on the reactive demand of the transmission system, the reactive capability  
3 of the units, the number of units on-line producing real power, and operation of the shunt  
4 reactor (which absorbs reactive power and reduces voltage). The method for assigning  
5 condensing units to the voltage control function and developing the forecast is described  
6 below.

7  
8 For the forecast, BPA first determines the total measured reactive demand that the  
9 transmission system placed on the six units only during the nighttime hours. This  
10 measured reactive demand is based on archived reactive meter readings for the historical  
11 three-year period. The total measured reactive demand represents the total reactive  
12 support (*e.g.*, megavolt amperes reactive) provided by all six units, regardless of whether  
13 the units are condensing or generating real power (units operating in generation mode also  
14 provide reactive support in addition to real power). For each hour, the total measured  
15 reactive demand is compared to the reactive capability of the units online generating real  
16 power plus, if not operating, the reactive capability of the shunt reactor.

17  
18 If the reactive capability of online units and the shunt reactor is less than the total  
19 measured reactive demand for the hour, one or more units operating in condense mode are  
20 allocated to voltage control for that hour. If a condensing unit is allocated to voltage  
21 control for a single nighttime hour, the condensing operation of that unit is allocated to  
22 voltage control for the entire nighttime period to reflect the fact that, in practice, a unit  
23 would not be started and stopped on an hourly basis. Condensing units are allocated to  
24 voltage control in whole increments until the total measured reactive demand is met or  
25 exceeded. The number of condensing hours for the three-year historical period is  
26 averaged, and energy consumption is determined by multiplying the average annual

1 condensing hours by the fixed hourly energy consumption of the generators. The forecast  
2 of total energy consumed by the Grand Coulee generators operating in synchronous  
3 condense mode for voltage control is 16,104 MWh/yr. Power Rates Study Documentation,  
4 BP-26-FS-BPA-01A, Table 9.3.2.1, line 4.

#### 6 **9.3.2.4.2 John Day, The Dalles, and Dworshak Projects**

7 The John Day project has four generators (Units 11-14), The Dalles has six generators  
8 (Units 15-20), and the Dworshak project has three generators (Units 1-3) capable of  
9 operating as synchronous condensers. These three projects condense only when requested  
10 by Transmission Services, so all hours in condense mode are assigned to voltage control.  
11 The number of condensing hours for the three-year historical period is averaged, and  
12 energy consumption is calculated by multiplying the average annual condensing unit hours  
13 by the fixed hourly energy consumption of the applicable hydro units. The forecast of total  
14 energy consumed by the generators operating in condense mode for voltage control is  
15 18,718 MWh/yr. for John Day and The Dalles (*id.*, line 3), and 350 MWh/yr. for the  
16 Dworshak project (*id.*, lines 5-6).

#### 18 **9.3.2.4.3 Palisades Project**

19 The Palisades project has four generators (Units 1-4) that are capable of synchronous  
20 condensing. Units are operated in condense mode pursuant to standing instructions from  
21 Transmission Services based on operational studies, so all hours in condense mode are  
22 assigned to voltage control. The number of condensing hours for the three-year historical  
23 period is averaged. Energy consumption is determined by multiplying the average annual  
24 condensing unit hours by the fixed hourly energy consumption of the project. The forecast  
25 of energy consumption by the Palisades generators operating in condense mode for voltage

1 control is 2,031 MWh/yr. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
2 Table 9.3.2.1, line 7.

#### 3 4 **9.3.2.4.4 Willamette River Projects**

5 The Willamette River projects have seven generators capable of condensing, which include  
6 units in the Detroit project (Units 1-2), the Green Peter project (Units 1-2), and the Lookout  
7 Point project (Units 1-3). Historically these units have been operated at times in condense  
8 mode. However, BPA studies indicate that condensing is not required from these projects  
9 for voltage support except under rare conditions. Therefore, the energy for condensing  
10 operation for voltage control is forecast to be zero for the Willamette River projects. *Id.*,  
11 lines 8-10.

#### 12 13 **9.3.2.4.5 Hungry Horse Project**

14 The Hungry Horse project has four generators (Units 1-4) capable of condensing. Although  
15 capable of condensing, Hungry Horse was not requested to operate in condense mode  
16 during the three-year historical period. Therefore, the energy consumption for the Hungry  
17 Horse generators is forecast to be zero. *Id.*, line 11.

#### 18 19 **9.3.2.5 Summary—Costs Assigned to Transmission Services**

20 Synchronous condensing costs assigned to Transmission Services are the investments in  
21 plant modifications and the energy consumed for condensing operation. As stated above,  
22 the investments in plant modifications at the John Day and The Dalles projects result in an  
23 average cost of \$189,333 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
24 Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-26-FS-  
25 BPA-02A, Table 2F.

1 The energy forecast to be consumed by FCRPS generators operating in condense mode  
2 totals 37,202 MWh. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1,  
3 line 13. The energy consumed for condensing operation is priced at the market price  
4 forecast. See Power Market Price Study and Documentation, BP-26-FS-BPA-04, § 2.4.  
5 Applying the market price forecast of \$38.91 per MWh to the energy consumed results in a  
6 total cost of \$1,447,543 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A,  
7 Table 9.3.2.1, line 13. This amount is made up of \$728,317 per year in energy costs for the  
8 Southern Intertie, and \$719,225 associated with energy costs for voltage control for the  
9 Network. *Id.*, lines 3, 12. Total synchronous condensing cost allocated to Transmission  
10 Services, then, is the sum of the \$189,333 per year in plant investments for the Southern  
11 Intertie and the total cost of energy consumed of \$1,447,543, which equals \$1,636,876 per  
12 year. *Id.*, Table 9.3.2.3, lines 1, 5.

13

### 14 **9.3.3 Generation Dropping**

#### 15 **9.3.3.1 Introduction**

16 This section describes the method for allocating costs of Generation Dropping, including  
17 identifying the assumptions used in the methodology and establishing the generation input  
18 cost allocation that is applied to determine the annual revenue forecast for generation  
19 inputs.

20

#### 21 **9.3.3.2 Generation Dropping Requirement**

22 The BPA transmission system is interconnected with several other transmission systems.  
23 To maximize the transmission capacity of these interconnections while maintaining  
24 reliability standards, Remedial Action Schemes (RAS) are developed for the transmission  
25 grids. These schemes automatically make changes to the system when a contingency  
26 occurs to maintain loadings and voltages within acceptable levels. Under one of these

1 schemes, Transmission Services requests that Power Services instantaneously drop  
2 (disconnect from the system) large increments of generation (at least 600 MW). To satisfy  
3 this requirement, the generation must be dropped virtually instantaneously from a certain  
4 region of the transmission grid. Under the current configuration of the transmission grid  
5 and the individual generating plant controls, Power Services can most expeditiously  
6 provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric  
7 units (each of which exceeds 600 MW capacity).

### 9 **9.3.3.3 General Methodology**

10 The methodology for calculating the cost of Generation Dropping starts with two factors:  
11 the impact to the equipment involved and the lost revenue associated with that impact.  
12 These factors are applied to a single generating unit at the Grand Coulee Third Powerhouse  
13 to arrive at an estimate of a single generation drop. This number is then multiplied by the  
14 estimated average drops per year to arrive at an estimate of the cost of Generation  
15 Dropping for each year of the rate period. Generation Dropping causes additional wear and  
16 tear on equipment that will decrease the life and increase the maintenance of the unit. For  
17 each major component that is affected by this service. Power Rates Study Documentation,  
18 BP-26-FS-BPA-01A, Table 9.3.3.1 shows the cost associated with incremental equipment  
19 deterioration, replacement, and overhaul, and the cost associated with incremental routine  
20 operation and maintenance.

21  
22 Historical data for the Grand Coulee Third Powerhouse generating units and statistical data  
23 for other hydroelectric units provide capital cost, operation and maintenance costs, and  
24 frequency of operation information for the Generation Dropping analysis. Stresses on the  
25 equipment from Generation Dropping versus stresses during normal operation are  
26 compared. Through the application of this data, the capital and operation and maintenance

1 costs for Generation Dropping are developed. The impacts are converted into a percentage  
2 change in equipment life and percentage increase in operations and maintenance for each  
3 operation.

#### 4 **9.3.3.4 Generation Dropping Cost**

##### 6 **9.3.3.4.1 Incremental Equipment Deterioration, Replacement, or Overhaul Costs**

7 One effect of additional deterioration because of Generation Dropping is a reduced period  
8 of time between major maintenance activities, such as major overhauls or replacements.

9 For purposes of this analysis, a “major overhaul” is defined as a maintenance activity for  
10 which at least partial disassembly of the affected equipment is required. The analysis  
11 focuses on evaluating the costs of additional, short-term deterioration of specific  
12 components or items for which statistical data are readily available. The costs of a major  
13 overhaul are derived from estimates or similar work performed in the past.

14 The percentage life reductions are determined using industry standards or actual project  
15 records. *See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.3.1,*  
16 *column B.* For example, turbine overhaul is a major maintenance effort that will increase in  
17 frequency as a result of Generation Dropping.

18  
19 Power Services previously contracted with Harza Engineering Company to work with  
20 Reclamation and the Corps (which operate and maintain the FCRPS projects) to evaluate  
21 the costs of providing Generation Dropping. The evaluation estimated the cost incurred by  
22 a typical Reclamation or Corps generating unit. These cost estimates are applied to a  
23 generating unit at the Grand Coulee Third Powerhouse. The costs in the original  
24 engineering study are updated using the Handy-Whitman Index to reflect price escalation  
25 of equipment and labor costs.

1 The Handy-Whitman Index multiplier is applied to the equipment costs in the study  
2 performed by Harza Engineering Company. The annual Incremental Equipment  
3 Deterioration, Replacement, and Overhaul Cost per drop for FY 2026-2028 is calculated by  
4 multiplying the percentage of Life Reduction per drop by the cost of a Major Overhaul. *Id.*,  
5 column D, line 6.

#### 7 **9.3.3.4.2 Incremental Routine Operation and Maintenance Costs**

8 In addition to more frequent major overhauls, increases in routine operations and  
9 maintenance costs are expected due to the additional deterioration caused by Generation  
10 Dropping. The Incremental Routine Operations and Maintenance (O&M) Cost per drop is  
11 calculated using the Percentage Increase O&M Per Drop and expected annual operations  
12 and maintenance costs per major piece of equipment. The percentage increase in O&M  
13 costs is assumed to be equivalent to the percentage life reductions used to determine the  
14 incremental deterioration, replacement, or overhaul costs (*e.g.*, a 0.1 percent reduction in  
15 life per drop will result in a 0.1 percent increase in annual O&M costs). Annual O&M costs  
16 are increased by an inflation factor of 2.35 percent for FY 2026-2028. The annual  
17 Incremental Routine O&M Cost per Drop for FY 2026-2028 is calculated by multiplying the  
18 Percentage Increase O&M Per Drop by the Annual O&M Cost. *See id.*, column G, line 6. It is  
19 assumed that these outages are longer than scheduled or unpredictable outages, and  
20 cannot be scheduled to avoid a loss in total project generation.

#### 22 **9.3.3.4.3 Incremental Lost Revenue in the Event of Replacement or Overhaul**

23 The revenue lost during outages for the overhaul or replacement of equipment is  
24 significant for the large generating units with a capacity exceeding 600 MW. Lost revenues  
25 are calculated based on the forecast market price averaged over the rate period, FY 2026-  
26 2028.

1 The Downtime Cost is calculated by multiplying the average monthly generation loss for a  
2 Unit 22, 23, or 24 outage by the assumed months of downtime for each piece of equipment  
3 by the market price forecast. *See* Power Market Price Study and Documentation, BP-26-  
4 FS-BPA-04, § 2.4. The annual Cost per Drop for FY 2026-2028 is calculated by multiplying  
5 the Probability of Failure by the Down Time Cost. Power Rates Study Documentation,  
6 BP-26-FS-BPA-01A, Table 9.3.3.1, column K, line 6.

### 7 8 **9.3.3.5 Costs to be Allocated to Transmission Services**

9 The factors described above are analyzed for their application on a single generating unit at  
10 the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall  
11 cost associated with each generation drop. From these analyses, the total cost associated  
12 with a single generator drop of one of the Grand Coulee Third Powerhouse Units is  
13 calculated to be \$714,375. *Id.*, column L, line 6.

14  
15 Historically, large generating units at Grand Coulee have been dropped 27 times over the  
16 last 28 years (1996 through 2024). Therefore, the average of approximately 1 drop per  
17 year is used as the Generation Dropping estimate.

18  
19 Multiplying the 1 drop per year by the cost of a single drop (\$714,375), the forecast annual  
20 cost is \$714,375. *Id.*, column D, line 7. This cost is assigned to Transmission Services for  
21 recovery in transmission rates. The rate period annual average cost for Generation  
22 Dropping is a revenue credit to the power rates. *See* Power Rates Study Documentation,  
23 BP-26-FS-BPA-01A, Table 9.3.1.1 line 10.

1 **9.3.4 Redispatch**

2 **9.3.4.1 Introduction**

3 Under the Tariff and the Redispatch and Curtailment Business Practice, Transmission  
4 Services can initiate redispatch as part of congestion management efforts. Generally,  
5 redispatch results in actions that can effectively relieve a transmission constraint that may  
6 impair the reliability of BPA’s transmission system and maintains service to loads.

7  
8 The Business Practice provides three types of redispatch that Transmission Services can  
9 request from Power Services to relieve congestion: Discretionary Redispatch, NT  
10 Redispatch, and Emergency Redispatch. Additionally, the Business Practice provides  
11 Power Services the ability to purchase transmission to ensure delivery to load, such as in  
12 the form of redispatch for stranded Load. Power Services may provide redispatch through  
13 *inc* and *dec* of federal generation, through purchases and/or sales of energy, or through  
14 transmission purchases. The purposes of each of these types of redispatch are discussed  
15 further below. The price of redispatch is calculated based on one of two sources,  
16 depending on how the redispatch is provided: 1) for redispatch provided from federal  
17 generation, market prices for incrementing and decrementing federal generation at the  
18 time the redispatch is provided; or 2) for redispatch provided by purchases and/or sales of  
19 energy or purchases of transmission, the actual cost to Power Services of purchasing  
20 and/or selling power or purchasing transmission.

21  
22 This Study forecasts the cost of redispatch that will be transferred as revenue to Power  
23 Services from Transmission Services for the provision of redispatch during the FY 2026-  
24 2028 rate period. The forecast is based on actual redispatch costs from October 2019 to  
25 August 2024.

1 **9.3.4.2 Discretionary Redispatch**

2 Under the Redispatch and Curtailment Business Practice, Transmission Services may  
3 request Discretionary Redispatch from federal resources to *inc* and *dec* generation prior to  
4 curtailment of any transmission schedules.

5  
6 Discretionary Redispatch totaled \$0 in FY 2020, \$0 in FY 2021, \$43,565 in FY 2022, \$0 in  
7 FY 2023, and \$12,500 in FY 2024 (through August), averaging \$11,419. Power Rates Study  
8 Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column B provides the actual annual  
9 Discretionary Redispatch details for October 2019 to August 2022. For FY 2026 through  
10 FY 2028, Transmission Services forecasts Discretionary Redispatch of \$ 11,419 per year.

11  
12 **9.3.4.3 Network Integration Redispatch**

13 Under the Redispatch and Curtailment Business Practice, Transmission Services requests  
14 NT Redispatch from Power Services to maintain firm NT schedules. NT Redispatch can be  
15 requested only after all non-firm Point-to-Point and secondary NT schedules are curtailed  
16 in a sequence consistent with NERC curtailment priority. Power Services must provide NT  
17 Redispatch when requested by Transmission Services to the extent that it can do so  
18 without violating non-power constraints.

19  
20 NT Redispatch totaled \$262,326 in FY 2020, \$87,437 in FY 2021, \$97,539 in FY 2022,  
21 \$51,492 in FY 2023, and \$30,414 in FY 2024 (through August), averaging \$107,782. *Id.*,  
22 columns C-D. Of this total amount from 2020 through August 2024, only \$9,541 was  
23 associated with Power Services providing NT Redispatch through the redispatch of federal  
24 generation or through power purchases or sales. The rest (\$519,668 over the same period)  
25 represents payments from Transmission Services to Power Services associated with  
26 NT Redispatch provided through transmission purchases only. Power Rates Study

1 Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1 provides, for FY 2020 through FY 2024  
2 (through August), the actual annual NT Redispatch cost. The NT Redispatch forecast for  
3 FY 2026-2028 is \$107,782 per year.

#### 4 5 **9.3.4.4 Emergency Redispatch**

6 Under the Redispatch and Curtailment Business Practice, Transmission Services may  
7 request Emergency Redispatch from Power Services to minimize the risk and/or scope of  
8 a transmission system reliability condition. Power Services must provide Emergency  
9 Redispatch when requested.

10  
11 Emergency Redispatch for FY 2020, FY 2021, FY 2022, FY 2023, and FY 2024 (through  
12 August) totaled \$0. The average from FY 2020 to FY 2024 (through August) was \$0.  
13 See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column E.

14  
15 Because Emergency Redispatch is a rare event, it is forecast to be \$0 for FY 2026-2028. *Id.*

#### 16 17 **9.3.4.5 Redispatch for Stranded Load**

18 Under the Redispatch and Curtailment Business Practice, Power Services may purchase  
19 transmission to ensure delivery to load. Specifically, BPA serves certain load that, in cases  
20 of planned outages, “strand” that load from being electrically connected to BPA and must  
21 be served through third-party transmission service. In these situations Power Services  
22 purchases the third-party transmission service to ensure delivery to BPA’s load is not  
23 interrupted. These redispatch for stranded load costs are then reimbursed by  
24 Transmission Services.

1 Redispatch for stranded load totaled \$71,779 in FY 2020, \$208,361 in FY 2021, \$203,618 in  
2 FY 2022, \$36,560 in FY 2023 and \$96,784 in FY 2024 (through August), averaging  
3 \$125,682. The redispatch for stranded load forecast for FY 2026-2028 is \$125,682 per  
4 year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column F.

#### 6 **9.3.4.6 Revenue Forecast for Redispatch Service**

7 Based on the analysis above, total revenues of \$244,883 per year is forecast for FY 2026-  
8 2028 for Redispatch services provided by Power Services to Transmission Services.

9 *Id.*, line 7.

### 11 **9.3.5 Station Service**

#### 12 **9.3.5.1 Introduction**

13 Station service refers to real power that Transmission Services takes directly off the BPA  
14 power system for use at substations and other locations, such as facilities located on BPA's  
15 Ross Complex and Big Eddy/Celilo Complex. For purposes of this Study, station service  
16 does not include power that BPA purchases from another utility or that is supplied by  
17 another utility for station service purposes. Because there are locations on the system  
18 where BPA does not have meters to measure station service use, the amount of energy use  
19 at BPA substations and other facilities is estimated. The annual average forecast market  
20 price from the Power Market Price Study, BP-26-FS-BPA-04, § 2.4, is applied to the  
21 estimated annual energy use adjusted for transmission losses to yield the annual costs that  
22 are allocated to Transmission Services for station service energy use. This section  
23 describes the station service energy use and the procedure used to determine the costs that  
24 are allocated to Transmission Services for station service energy use.

1 **9.3.5.2 Overview of Methodology**

2 The station service costing methodology consists of the following steps: First, a historical  
3 monthly average station service energy use was determined based on measured load data  
4 for a sample of BPA's substations based on size (large, medium, and small). Second, an  
5 average load factor of 9.45 percent was derived based on the ratio of installed station  
6 service transformation and energy use for those substations. Third, that average load  
7 factor of 9.45 percent is then applied to the total amount of installed transformation,  
8 measured in kilovolt amperes (kVA), at all BPA substations served directly by the BPA  
9 power system to determine a total usage. Fourth, the station service energy use for all  
10 facilities other than the Ross and Big Eddy/Celilo complexes is estimated by applying the  
11 average load factor to the total installed station service transformer capacity. This energy  
12 use is then added to the historical use for the Ross and Big Eddy/Celilo complexes to  
13 estimate total average monthly energy use. The monthly amount is multiplied by 12 to  
14 yield an annual average estimated total energy use for all substations, which is then  
15 adjusted for transmission losses by applying the BPA network loss factor, 2.05 percent.  
16 The annual average forecast market price from the Power Market Price Study, BP-26-  
17 FS-BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission  
18 losses to yield the annual costs that are allocated to Transmission Services for station  
19 service energy use.

20  
21 **9.3.5.3 Assessment of Installed Transformation**

22 This methodology begins by identifying the amount of installed transformation for all BPA  
23 substations. Installed transformation transforms power to a lower voltage to supply power  
24 to the buildings and equipment at the substations. The total installed transformation is  
25 46,784 kVA. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.5.2, line 6.

1 Of this amount, the total amount of installed transformation at BPA substations for which  
2 load data exists is 15,456 kVA. *Id.*, Table 9.3.5.1, line 41.

#### 3 4 **9.3.5.4 Assessment of Station Service Energy Use**

5 The historical average monthly use for the Ross Complex is 1,749,300 kWh, and for Big  
6 Eddy/Celilo Complex is 1,822,937 kWh, for a total of 3,572,237 kWh. *Id.*, Table 9.3.5.2,  
7 lines 4-5.

8  
9 The total historical average monthly use for other BPA locations for which load data exists  
10 is 1,066,446 kWh. *Id.*, Table 9.3.5.1, line 41. Because not all use is metered, the total  
11 average monthly use for BPA substations is estimated based on the historical average  
12 monthly use multiplied by the average load factor. *Id.*, Table 9.3.5.2, lines 1-3.

#### 13 14 **9.3.5.5 Calculation of Average Load Factor**

15 The average monthly load factor is calculated by dividing the total historical monthly use  
16 for BPA substations for which load data is available by the total installed station service  
17 transformation for these BPA substations. This yields an average 9.45 percent load factor.  
18 *Id.*, Table 9.3.5.1, line 41.

#### 19 20 **9.3.5.6 Calculating the Total Station Service Average Use**

21 The total installed transformation is multiplied by the average calculated load factor to  
22 yield the calculated historical average monthly use for all facilities other than the Ross and  
23 Big Eddy/Celilo complexes. *See id.*, Table 9.3.5.2, lines 1-3. The historical station service  
24 energy use for the Ross Complex and the Big Eddy/Celilo Complex is then added to the  
25 calculated amount of energy use at all other BPA substations. *Id.*, lines 4-5. The total  
26 quantity of station service average use that Power Services supplies directly to BPA

1 substations and other facilities is then adjusted for transmission losses by multiplying the  
2 average use by the BPA Transmission Network loss factor of 2.05 percent pursuant to  
3 Schedule 11 of BPA's Tariff. The adjusted quantity of station service average use supplied  
4 to BPA substations and other facilities after adding in the network losses is estimated to be  
5 81,604 MWh per year. *Id.*, line 6.

### 7 **9.3.5.7 Determining Costs to Allocate to Station Service**

8 The annual average forecast market price (*see* Power Market Price Study, BP-26-  
9 FS-BPA-04, § 2.4) applied to the estimated annual quantity of station service energy use,  
10 including network losses, yields the energy costs per year to be allocated to Station Service.  
11 The capacity rate for Real Power Losses (Section 4.4.2) applied to the estimated quantity of  
12 network losses, yields the capacity costs associated with network losses. The sum of the  
13 energy costs and the capacity costs associated with Real Power Losses equals the total  
14 costs to allocate to station service. This rate period annual average cost is \$3.265 million.  
15 Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.5.2, line 6.

### 17 **9.3.5.8 Impact on Power Rates and Transmission Rates**

18 The rate period annual average cost for station service is a revenue credit to the power  
19 rates. *See id.*, Table 9.3.1.1, line 13.

## 21 **9.4 Revenue from Treasury Credits**

22 Revenues are also forecast from two kinds of Treasury credits, or deductions, made from  
23 BPA's annual Treasury payment. These credits represent a partial reimbursement by the  
24 Treasury for expenses incurred by BPA throughout the year.

1 **9.4.1 Section 4(h)(10)(C) Credits**

2 BPA pays all the costs relating to the obligations of Northwest Power Act  
3 Section 4(h)(10)(C) regarding protecting, enhancing, and mitigating fish and wildlife in the  
4 region. 16 U.S.C. § 839b(h)(10)(C). BPA is reimbursed by the U.S. Treasury for  
5 22.3 percent of the replacement power purchases BPA is expected to make due to fish  
6 mitigation, as well as an equal percentage of program and capital expenses related to the  
7 fish and wildlife programs. The 22.3 percent represents the non-power portion of the total  
8 FCRPS costs, which is the responsibility of taxpayers rather than BPA ratepayers. This  
9 Treasury credit is treated as Power Services revenue.

10  
11 Expenses relating to fish and wildlife programs are discussed in the Power Revenue  
12 Requirement Study, BP-26-FS-BPA-02, Section 1.2.1.4. The methodology for estimating the  
13 replacement power purchases resulting from changes in hydro system operations to  
14 benefit fish and wildlife is described in the Power Loads and Resources Study, BP-26-  
15 FS-BPA-03, Section 3.3.1. The cost of the increased purchases is estimated using RevSim  
16 and the market price forecast and is included in the Power and Transmission Risk Study,  
17 BP-26-FS-BPA-05, Section 4.1.1.1.5.6, and the Power and Transmission Risk Study  
18 Documentation, BP-26-FS-BPA-05A, Table 13. Forecast 4(h)(10)(C) credits are listed in  
19 Table 4 of this Study, line 23, and Power Rates Study Documentation, BP-26-FS-BPA-01A,  
20 Table 9.2, line 49.

21  
22 **9.4.2 Colville Settlement Credits**

23 The Colville Settlement Agreement obligates BPA to make annual payments to the Colville  
24 Tribes. BPA receives annual credits from the U.S. Treasury against payments due the  
25 Treasury to defray a portion of the costs of making payments to the Colville Tribes. The  
26 Treasury credit for the Colville Settlement in FY 2026, FY 2027, and FY 2028 is set by  
27 legislation at \$4.6 million per year. *See* Confederated Tribes of the Colville Reservation

1 Grand Coulee Settlement Act, Pub. L. No. 103-436, 108 Stat. 4577 (Nov. 2, 1994). The credit  
2 is shown on Table 4 of this Study, line 24, and Power Rates Study Documentation, BP-26-  
3 FS-BPA-01A, Table 9.2, line 50.

## 4 5 **9.5 Power Purchase Expense Forecast**

6 Power Services forecasts three types of power purchase expenses: Augmentation  
7 Purchases, Balancing Purchases, and Other Power Purchases. Although most expenses,  
8 including some power purchase expenses, such as long-term generating resources, are  
9 forecast in the Power Revenue Requirement Study, the power purchase expenses described  
10 here are directly related to load, resource, and price assumptions used to develop power  
11 rates. Therefore, they are included in the Power Services revenue forecast.

### 12 13 **9.5.1 Augmentation Purchase Expense**

14 For planning purposes, the forecast of firm FCRPS output is based upon firm generation  
15 conditions. *See* Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.3. The  
16 forecast annual firm FCRPS output under firm generation conditions plus the output of  
17 other federal resources may not be adequate to meet annual average firm loads. Therefore,  
18 system augmentation is added to federal resources to balance firm annual resources with  
19 firm annual loads. The forecast expense for the augmentation is based on the remarketing  
20 value. *See* Section 3.2.6 above. Augmentation purchase amounts for FY 2025-2028 are  
21 listed in Table 4 of this Study, line 26, and Power Rates Study Documentation, BP-26-  
22 FS-BPA-01A, Table 9.2, line 52.

23  
24 The cost of uncommitted market purchases for Tier 2 augmentation in FY 2025-2028 is  
25 listed in Table 4 of this Study, line 28, and Power Rates Study Documentation, BP-26-  
26 FS-BPA-01A, Table 9.2, line 54.

1 **9.5.2 Total Balancing Costs**

2 Total balancing costs include balancing power purchases calculated by RevSim and  
3 committed purchases BPA has made to serve preference customer loads in Southeastern  
4 Idaho.

5  
6 RevSIM calculates the balancing power purchases by finding any monthly HLH and LLH  
7 energy deficits by simulations of 40 iterations in each of the 30 water years, for a total of  
8 2,700 iterations, and application of the corresponding market prices developed for each  
9 iteration. Similar to the treatment of short-term market sales, the median value for  
10 balancing purchases over the 2,700 iterations is reported for FY 2025 for forecast months  
11 and added to actual purchases in past months, and the median value is reported for  
12 FY 2025-2028. Total balancing purchase expense for FY 2025-2028 is listed in Table 4 of  
13 this Study, line 27, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2,  
14 line 53. A full description is found in the Power and Transmission Risk Study, BP-26-  
15 FS-BPA-05, Section 4.1.1.2.2.

16  
17 Total balancing costs include committed purchases BPA has made to serve preference  
18 customer loads in Southeastern Idaho. *See* Power Rates Study Documentation, BP-26-  
19 FS-BPA-01A, Table 2.3.2. In those months and water years in which firm loads exceed  
20 resources, Southeast Idaho Load Service (SILS) purchases reduce balancing purchases.  
21 Conversely, in those months and water years in which resources are sufficient to serve firm  
22 loads, SILS purchases increase the amount of surplus sales. RevSim accounts for the energy  
23 related to SILS purchases in the balancing purchases category. A full description is found in  
24 the Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.1.1.2.1, and in Section  
25 6.6 of this Study.

1 **9.5.3 Other Augmentation**

2 Total Other Augmentation expense for FY 2025-2028 is listed in Table 4 of this Study,  
3 line 29, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 55.

4

5 **9.6 Summary of Power Revenues**

6 A detailed summary of power revenues at current and proposed rates is found in Tables 3  
7 and 4 of this Study, and in Power Rates Study Documentation, BP-26-FS-BPA-01A,  
8 Tables 9.1 and 9.2.

## **POWER RATES TABLES**

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**Table 1: Rate Period High Water Marks for FY 2026-2028**

<b>Table of RHWMs for FY 2026-2028</b>			
	<i>A</i>	<i>B</i>	<i>C</i>
	<b>Customer ID</b>	<b>Customer Name</b>	<b>RHWM annual aMW</b>
1	10055	Albion, City of	0.400
2	10057	Ashland, City of	21.190
3	10015	Asotin County PUD #1	0.577
4	10059	Bandon, City of	7.683
5	10024	Benton County PUD #1	202.081
6	10025	Benton REA	60.003
7	10027	Big Bend Elec Coop	61.547
8	10029	Blachly Lane Elec Coop	17.718
9	10061	Blaine, City of	8.797
10	10062	Bonnors Ferry, City of	5.350
11	10064	Burley, City of	14.145
12	10044	Canby, City of	20.426
13	10065	Cascade Locks, City of	2.391
14	10046	Central Electric Coop	82.323
15	10047	Central Lincoln PUD	157.576
16	10066	Centralia, City of	24.512
17	10067	Cheney, City of	15.908
18	10068	Chewelah, City of	2.786
19	10101	Clallam County PUD #1	76.466
20	10103	Clark County PUD #1	320.329
21	10105	Clatskanie PUD	93.373
22	10106	Clearwater Power	24.016
23	10109	Columbia Basin Elec Coop	12.188
24	10111	Columbia Power Coop	3.253
25	10113	Columbia REA	37.910
26	10112	Columbia River PUD	58.586
27	10116	Consolidated Irrigation District #19	0.229
28	10118	Consumers Power	45.937
29	10121	Coos Curry Elec Coop	41.111
30	10378	Coulee Dam, City of	2.033
31	10123	Cowlitz County PUD #1	552.365
32	10070	Declo, City of	0.361

<b>Table of RHWMs for FY 2026-2028</b>			
	<i>A</i>	<i>B</i>	<i>C</i>
	<b>Customer ID</b>	<b>Customer Name</b>	<b>RHWM annual aMW</b>
33	10136	Douglas Electric Cooperative	18.644
34	10071	Drain, City of	1.925
35	10142	East End Mutual Electric	2.702
36	10144	Eatonville, City of	3.387
37	10072	Ellensburg, City of	24.120
38	10156	Elmhurst Mutual P & L	32.424
39	10157	Emerald PUD	50.246
40	10158	Energy Northwest	2.807
41	10170	Eugene Water & Electric Board	252.544
42	10173	Fall River Elec Coop	33.321
43	10174	Farmers Elec Coop	0.510
44	10177	Ferry County PUD #1	11.732
45	10179	Flathead Elec Coop	167.784
46	10074	Forest Grove, City of	26.836
47	10183	Franklin County PUD #1	118.028
48	10186	Glacier Elec Coop	21.440
49	10190	Grant County PUD #2	5.221
50	10191	Grays Harbor PUD #1	131.973
51	10197	Harney Elec Coop	22.884
52	10597	Hermiston, City of	13.012
53	10076	Heyburn, City of	4.845
54	10202	Hood River Elec Coop	13.174
55	10203	Idaho County L & P	6.249
56	10204	Idaho Falls Power	80.015
57	10209	Inland P & L	105.495
58	12026	Jefferson County PUD #1	45.433
59	13927	Kalispel Tribe Utility	4.097
60	10230	Kittitas County PUD #1	9.758
61	10231	Klickitat County PUD #1	36.870
62	10234	Kootenai Electric Coop	51.293
63	10235	Lakeview L & P (WA)	33.304
64	10236	Lane County Elec Coop	29.271
65	10237	Lewis County PUD #1	114.388
66	10239	Lincoln Elec Coop (MT)	14.081

<b>Table of RHWMs for FY 2026-2028</b>			
	<i>A</i>	<i>B</i>	<i>C</i>
	<b>Customer ID</b>	<b>Customer Name</b>	<b>RHWM annual aMW</b>
67	10242	Lost River Elec Coop	9.581
68	10244	Lower Valley Energy	86.533
69	10246	Mason County PUD #1	9.039
70	10247	Mason County PUD #3	80.389
71	10078	McCleary, City of	3.739
72	10079	McMinnville, City of	88.687
73	10256	Midstate Elec Coop	47.015
74	10080	Milton, Town of	7.480
75	10081	Milton-Freewater, City of	10.515
76	10082	Minidoka, City of	0.119
77	10258	Mission Valley	38.171
78	10259	Missoula Elec Coop	27.141
79	10260	Modern Elec Coop	26.436
80	10083	Monmouth, City of	8.411
81	10273	Nespelem Valley Elec Coop	5.915
82	10278	Northern Lights	36.135
83	10279	Northern Wasco County PUD	65.138
84	10284	Ohop Mutual Light Company	10.768
85	10285	Okanogan County Elec Coop	6.566
86	10286	Okanogan County PUD #1	46.176
87	10288	Orcas P & L	24.877
88	10291	Oregon Trail Coop	79.638
89	10294	Pacific County PUD #2	36.536
90	10304	Parkland L & W	14.149
91	10306	Pend Oreille County PUD #1	25.917
92	10307	Peninsula Light Company	72.400
93	10086	Plummer, City of	3.968
94	10298	PNGC Aggregate	762.537
95	10087	Port Angeles, City of	85.973
96	10706	Port of Seattle - SETAC In'tl. Airport	17.378
97	10331	Raft River Elec Coop	36.813
98	10333	Ravalli County Elec Coop	18.622
99	10089	Richland, City of	104.814
100	10338	Riverside Elec Coop	2.386

<b>Table of RHWMs for FY 2026-2028</b>			
	<i>A</i>	<i>B</i>	<i>C</i>
	<b>Customer ID</b>	<b>Customer Name</b>	<b>RHWM annual aMW</b>
101	10091	Rupert, City of	9.477
102	10342	Salem Elec Coop	38.914
103	10343	Salmon River Elec Coop	31.570
104	10349	Seattle City Light	526.931
105	10352	Skamania County PUD #1	15.998
106	10354	Snohomish County PUD #1	803.675
107	10094	Soda Springs, City of	3.054
108	10360	Southside Elec Lines	6.804
109	10363	Springfield Utility Board	101.286
110	10379	Steilacoom, Town of	4.836
111	10095	Sumas, Town of	3.664
112	10369	Surprise Valley Elec Coop	16.527
113	10370	Tacoma Public Utilities	404.709
114	10371	Tanner Elec Coop	11.096
115	10376	Tillamook PUD #1	56.352
116	10097	Troy, City of	2.049
117	10172	U.S. Airforce Base, Fairchild	6.137
118	10406	U.S. DOE Albany Research Center	0.461
119	10426	U.S. DOE Richland Operations Office	42.226
120	10326	U.S. Naval Base, Bremerton	30.635
121	10408	U.S. Naval Station, Everett (Jim Creek)	1.536
122	10409	U.S. Naval Submarine Base, Bangor	20.539
123	10388	Umatilla Elec Coop	113.876
124	10482	Umpqua Indian Utility Cooperative	4.137
125	10391	United Electric Coop	30.150
126	10434	Vera Irrigation District	27.313
127	10436	Vigilante Elec Coop	19.263
128	10440	Wahkiakum County PUD #1	5.034
129	10442	Wasco Elec Coop	13.473
130	11680	Weiser, City of	6.365
131	10446	Wells Rural Elec Coop	96.323
132	10448	West Oregon Elec Coop	8.530
133	10451	Whatcom County PUD #1	26.987
134	10502	Yakama Power	18.815

**Table 2: Overview of BP-26 Final Proposal Rates**

**Tiered PF Rate Summary**

1	A	B	C	D
2		<b>BP-26</b>	<b>% above BP-24</b>	
3	Unbifurcated PF	\$ 52.63	9.0%	
4	PF Public (Tier 1 + Tier 2)	\$ 40.16	12.2%	
5	PF Exchange	\$ 75.98	7.8%	
6	IP	\$ 45.60	10.2%	
7	NR	\$ 111.27	30.4%	
9	<b>Annual Average \$ (1000s)</b>	<b>BP-24</b>	<b>BP-26</b>	<b>Change</b>
10	Composite Rate Revenues	\$2,380,887	\$2,448,350	2.8%
11	Non-Slice Rate Revenues	\$(331,991)	\$(366,991)	-10.5%
12	Slice Rate Revenues	\$-	\$-	
13	Load Shaping Rate Revenues	\$60,953	\$73,880	21.2%
14	Demand Rate Revenues	\$61,442	\$148,772	142.1%
15	Tier 1 Revenue Requirement	\$2,171,291	\$2,304,011	6.1%
16	Tier 2 Revenue Requirement	\$160,289	\$344,445	114.9%
17	Value of Slice Surplus	\$(111,312)	\$(57,713)	48.2%
18	Value of CHWM RECs (credit)	Not applicable for BP-26		
19	Lookback Return (credit)	Not applicable for BP-26		
20	Net Power Cost to All PF	\$2,220,268	\$2,590,743	16.7%
21	Surcharges	\$-	\$-	
22	Annual PF Load (w/firm Slice) (GWh)	61,983	64,506	4.1%
23	PF Average Net Cost (\$/MWh)	\$ 35.82	\$ 40.16	12.1%
25	Tier 1 Average Net Cost without FRP	\$ 34.69	\$ 37.77	8.9%
26	Tier 1 Average Net Cost max FRP	Not applicable for BP-26		
27	Tier 2 Short-Term (\$/MWh)	\$ 61.50	\$ 68.51	11.4%
29	<b>Slice Sales</b>	<b>BP-24</b>	<b>BP-26</b>	<b>Change</b>
30	Composite+Slice	\$491,768	\$301,796	
31	Surcharges	\$-	\$-	
32	Tier 1 Average Cost (\$/MWh)	\$40.21	\$41.22	2.5%
33	Value of Slice Surplus Credits	\$(111,312)	\$(57,713)	
34	Net Cost of Slice Power	\$380,456	\$244,082	
35	Tier 1 Average Net Cost (\$/MWh)	\$ 31.11	\$ 33.34	7.2%
37	<b>Non-Slice Sales</b>	<b>BP-24</b>	<b>BP-26</b>	<b>Change</b>
38	Composite+NonSlice+Shape+Demand	\$1,679,622	\$2,002,363	
39	Tier 1 Average Cost (\$/MWh)	\$35.63	\$38.40	7.8%
40	Credits	\$-	\$-	
41	Net Cost of Non-Slice Power	\$1,679,622	\$2,002,363	
42	Surcharges	Not applicable for BP-26		
43	Tier 1 Average Net Cost without FRP	\$ 35.63	\$ 38.40	7.8%
44	Tier 1 Average Net Cost max FRP	Not applicable for BP-26		
46	<b>Tiered PF Rate Components</b>	<b>BP-24</b>	<b>BP-26</b>	<b>Change</b>
47	Composite Rate (\$/ pct/month)	\$2,075,946	\$2,141,296	3.1%
48	Non-Slice Rate (\$/ pct/month)	\$(364,823)	\$(366,092)	0.3%

**Table 3: Revenues at Current Rates**

	A	B	C	D	E	F	G	H	I	J	K	L
1	<b>Revenues at Current Rates</b>				<b>2025</b>		<b>2026</b>		<b>2027</b>		<b>2028</b>	
2	<b>Category</b>				<b>\$ (000's)</b>	<b>aMW</b>	<b>\$ (000's)</b>	<b>aMW</b>	<b>\$ (000's)</b>	<b>aMW</b>	<b>\$ (000's)</b>	<b>aMW</b>
3	Composite Revenue				\$2,371,835	5,323	\$2,363,988	5,916	\$2,374,213	6,776	\$2,382,532	6,800
4	Non-Slice Revenue				(\$330,400)	-	(\$364,084)	-	(\$365,881)	-	(\$367,343)	-
5	Slice				\$0	1,403	\$0	840	\$0	826	\$0	842
6	Load Shaping Revenue				\$60,782	24	\$45,408	4	\$49,590	16	\$46,056	3
7	Demand Revenue				\$68,661	-	\$129,117	-	\$135,109	-	\$142,389	-
8	Irrigation Rate Discount				(\$21,737)	-	(\$21,770)	-	(\$21,770)	-	(\$21,770)	-
9	Low Density Discount				(\$33,490)	-	(\$38,116)	-	(\$38,116)	-	(\$38,116)	-
10	Tier 2				\$199,730	391	\$298,286	538	\$304,931	588	\$335,477	627
11	RSS (Non-Federal) and Other				\$221	-	\$1,056	-	\$1,036	-	\$1,046	-
12	PF customers (CHWM) sub-total				<b>\$2,315,602</b>	<b>7,140</b>	<b>\$2,413,884</b>	<b>7,298</b>	<b>\$2,439,112</b>	<b>8,206</b>	<b>\$2,480,271</b>	<b>8,272</b>
13	NR sub-total				(\$3,919)	(0)	\$0	1	\$0	20	\$0	25
14	DSIs sub-total				\$4,266	8	\$3,987	11	\$3,987	11	\$3,999	11
15	FPS sub-total				\$11,150	-	\$9,852	-	\$10,063	-	\$10,346	-
16	Short-term market sales sub-total				\$588,214	1,482	\$746,846	1,729	\$618,090	1,738	\$645,514	1,758
17	Long Term Contractual Obligations sub-total				\$0	-	\$0	-	\$0	-	\$0	-
18	Canadian Entitlement Return				\$0	462	\$0	462	\$0	462	\$0	461
19	Other Sales sub-total				(\$33,259)	-	\$0	-	\$0	-	\$0	-
20	<b>Gross Sales</b>				<b>\$2,882,054</b>	<b>9,093</b>	<b>\$3,174,570</b>	<b>9,501</b>	<b>\$3,071,251</b>	<b>10,437</b>	<b>\$3,140,130</b>	<b>10,528</b>
21	<b>Miscellaneous Revenues</b>				<b>\$28,175</b>	<b>175</b>	<b>\$24,778</b>	<b>175</b>	<b>\$24,769</b>	<b>175</b>	<b>\$24,749</b>	<b>175</b>
22	<b>Generation Inputs / Inter-business line</b>				<b>\$113,167</b>	<b>9</b>	<b>\$115,267</b>	<b>9</b>	<b>\$133,903</b>	<b>9</b>	<b>\$150,512</b>	<b>9</b>
23	4(h)(10)(c)				\$146,741	-	\$124,911	-	\$131,117	-	\$132,163	-
24	Colville Settlement				\$4,600	-	\$4,600	-	\$4,600	-	\$4,600	-
25	<b>Treasury Credits</b>				<b>\$151,341</b>	<b>-</b>	<b>\$129,511</b>	<b>-</b>	<b>\$135,717</b>	<b>-</b>	<b>\$136,763</b>	<b>-</b>
26	Augmentation Power Purchase total				\$0	-	\$0	-	\$0	-	\$0	-
27	Balancing Power Purchase sub-total				\$454,090	1,129	\$104,101	211	\$83,251	178	\$98,969	209
28	Tier 2 Augmentation total				\$0	-	\$319,432	554	\$329,517	599	\$354,163	638
29	Other Augmentation total				\$0	-	\$7,021	12	\$17,440	31	\$20,974	38
30	<b>Power Purchases</b>				<b>\$454,090</b>	<b>1,129</b>	<b>\$430,554</b>	<b>777</b>	<b>\$430,208</b>	<b>809</b>	<b>\$474,106</b>	<b>885</b>

**Table 4: Revenues at Proposed Rates**

	A	B	C	D	E	F	G	H	I	J	K	L
1	Revenues at Proposed Rates			2025		2026		2027		2028		
2	Category			\$ (000's)	aMW	\$ (000's)	aMW	\$ (000's)	aMW	\$ (000's)	aMW	
3	Composite Revenue			\$2,371,835	5,323	\$2,438,459	5,916	\$2,449,006	6,776	\$2,457,587	6,800	
4	Non-Slice Revenue			(\$330,400)	-	(\$365,300)	-	(\$367,103)	-	(\$368,571)	-	
5	Slice			\$0	1,403	\$0	840	\$0	826	\$0	842	
6	Load Shaping Revenue			\$60,782	24	\$72,093	4	\$76,824	16	\$72,724	3	
7	Demand Revenue			\$68,661	-	\$141,637	-	\$148,212	-	\$156,468	-	
8	Irrigation Rate Discount			(\$21,737)	-	(\$22,034)	-	(\$22,034)	-	(\$22,034)	-	
9	Low Density Discount			(\$33,490)	-	(\$42,155)	-	(\$43,297)	-	(\$44,391)	-	
10	Tier 2			\$199,730	391	\$328,238	538	\$339,794	588	\$365,302	627	
11	RSS (Non-Federal) and Other			\$221	-	\$836	-	\$5,582	-	\$4,839	-	
12	PF customers (CHWM) sub-total			\$2,315,602	7,140	\$2,551,774	7,298	\$2,586,983	8,206	\$2,621,924	8,272	
13	NR sub-total			(\$3,919)	(0)	\$10,208	1	\$30,593	20	\$38,924	25	
14	DSIs sub-total			\$4,266	8	\$4,394	11	\$4,394	11	\$4,406	11	
15	FPS sub-total			\$11,150	-	\$9,852	-	\$10,063	-	\$10,346	-	
16	Short-term market sales sub-total			\$588,214	1,482	\$746,846	1,729	\$618,090	1,738	\$645,514	1,758	
17	Long Term Contractual Obligations sub-total			\$0	-	\$0	-	\$0	-	\$0	-	
18	Canadian Entitlement Return			\$0	462	\$0	462	\$0	462	\$0	461	
19	Other Sales sub-total			(\$33,259)	-	\$0	-	\$0	-	\$0	-	
20	<b>Gross Sales</b>			<b>\$2,882,054</b>	<b>9,093</b>	<b>\$3,323,075</b>	<b>9,501</b>	<b>\$3,250,123</b>	<b>10,437</b>	<b>\$3,321,114</b>	<b>10,528</b>	
21	<b>Miscellaneous Revenues</b>			<b>\$28,175</b>	<b>175</b>	<b>\$24,778</b>	<b>175</b>	<b>\$24,769</b>	<b>175</b>	<b>\$24,749</b>	<b>175</b>	
22	<b>Generation Inputs / Inter-business line</b>			<b>\$113,167</b>	<b>9</b>	<b>\$115,267</b>	<b>9</b>	<b>\$133,903</b>	<b>9</b>	<b>\$150,512</b>	<b>9</b>	
23	4(h)(10)(c)			\$146,741	-	\$124,911	-	\$131,117	-	\$132,163	-	
24	Colville Settlement			\$4,600	-	\$4,600	-	\$4,600	-	\$4,600	-	
25	<b>Treasury Credits</b>			<b>\$151,341</b>	<b>-</b>	<b>\$129,511</b>	<b>-</b>	<b>\$135,717</b>	<b>-</b>	<b>\$136,763</b>	<b>-</b>	
26	Augmentation Power Purchase total			\$0	-	\$0	-	\$0	-	\$0	-	
27	Balancing Power Purchase sub-total			\$454,090	1,129	\$104,101	211	\$83,251	178	\$98,969	209	
28	Tier 2 Augmentation total			\$0	-	\$319,432	554	\$329,517	599	\$354,163	638	
29	Other Augmentation total			\$0	-	\$7,021	12	\$17,440	31	\$20,974	38	
30	<b>Power Purchases</b>			<b>\$454,090</b>	<b>1,129</b>	<b>\$430,554</b>	<b>777</b>	<b>\$430,208</b>	<b>809</b>	<b>\$474,106</b>	<b>885</b>	

**Table 5: Adjustments to Financial Reserves Base Account**

	B	C	D	E	F	G
1	Unit	Account	Stat Amt	Ref	Line Descr	Reason for adjustment
2	POWER	999044	\$ (673,094.63)	AR00114197	Receipt from DOJ	1
3	POWER	999044	\$ (104,552.35)	AR00117261	Receipt from FERC	1
4	POWER	999044	\$ (53,497.33)	AR00119524	Receipt from DOJ	1
5	POWER	999044	\$ (2,789.38)	AR00122086	Receipt from DOJ	1
6	POWER	999044	\$ (5.04)	AR00129431	Stock dividend	2
7	POWER	999044	\$ (6,667.74)	AR00127956	Receipt from FERC	1
8	POWER	999044	\$ (1,528.11)	AR00128358	Receipt from DOJ	1
9	POWER	999044	\$ (1,080.25)	AR00143938	Receipt from DOJ	1
10	POWER	999044	\$ (2,700.63)	AR00152218	Receipt from DOJ	1
11	POWER	999044	\$ (43,791.87)	AR00153347	Receipt from FERC	1
12	POWER	999044	\$ (5.04)	AR00144929	Stock dividend	2
13	POWER	999044	\$ (5.04)	AR00147994	Stock dividend	2
14	POWER	999044	\$ (5.04)	AR00151401	Stock dividend	2
15	POWER	999044	\$ (5.04)	AR00156308	Stock dividend	2
16	POWER	999044	\$ (5.04)	AR00158673	Stock dividend	2
17	POWER	999044	\$ (73,765,314.86)		CAL ISO/PX Receipt	1
18	POWER	999044	\$ (41,271.39)	AR00242805	Receipt from FERC CA Refund	1
19	POWER	999045	\$ (16,300,000.00)	AR00249656	Settlement	1
20						
21			\$ (90,996,318.78)			
22						

23 Reasons for adjustments

- 24 1) BPA's receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002.
- 25 2) BPA's receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002.
- 26 3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002.
- 28 Base amount of financial reserves = \$495,600,000
- 30 Adjustment to the base amount of financial reserves = \$495,600,000 + \$90,996,319
- 32 **Resulting amount of financial reserves = \$586,596,319**
- 34 Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount.
- 35 Adjustment amounts, if positive, are subtracted from the base amount of financial reserves, thereby decreasing the size of the base amount.

**Table 6: Residential Exchange Benefits**  
**(\$000)**

	A	B	C	D
1		<b>FY 2026</b>	<b>FY 2027</b>	<b>FY 2028</b>
2	Avista Corporation	\$9,253	\$9,253	\$9,278
3	Idaho Power Company	\$2,997	\$2,997	\$3,006
4	NorthWestern Energy, LLC	\$6,200	\$6,200	\$6,217
5	PacifiCorp	\$111,415	\$111,415	\$111,720
6	Portland General Electric Company	\$78,906	\$78,906	\$79,122
7	Puget Sound Energy, Inc.	\$77,068	\$77,068	\$77,279
8	<b>Net IOU Exchange</b>	<b>\$285,839</b>	<b>\$285,839</b>	<b>\$286,622</b>
9	Refund Amt	\$ -	\$ -	\$ -
10	<b>Total IOU REP Benefits (Rate Period Average)</b>			<b>\$286,100</b>
11	Clark Public Utilities	\$ -	\$ -	\$ -
12	Franklin	\$ -	\$ -	\$ -
13	Snohomish County PUD No 1	\$1,212	\$1,229	\$1,253
14	<b>Net COU Exchange</b>	<b>\$1,212</b>	<b>\$1,229</b>	<b>\$1,253</b>
15	<b>Total REP Benefits (Rate Period Average)</b>			<b>\$287,331</b>

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# **Appendix A: 7(c)(2) Industrial Margin Study**

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## APPENDIX A

### 7(c)(2) Industrial Margin Study

#### 1. INTRODUCTION

The purpose of this appendix is to describe BPA's calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-26 energy rates, which become the energy rates used in the IP-26 rate for BPA's direct-service industrial customers (DSIs).

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to BPA's DSI customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account:

1. the comparative size and character of the loads served;
2. the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and
3. direct and indirect overhead costs, all as related to the delivery of power to industrial customers.

## **2. METHODOLOGY**

### **2.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers**

The Administrator's applicable wholesale rates to public body and cooperative customers are the PF-26 demand and energy rates before any 7(b)(2) or floor rate adjustments are applied.

### **2.2 Typical Margin**

The typical margin is based generally on the overhead costs that consumer-owned utilities add to the cost of power in setting their retail industrial rates; *see* Section 2.3 below.

### **2.3 Margin Determination Factors**

**Comparative Size and Character of the Loads Served.** The data base used for the study includes utilities that serve at least one industrial consumer with a peak demand of at least 3.5 MW.

**Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions.** The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate costs allocated to the industrial consumer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in the industrial margin calculation.

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile of DSI load, which was interruptible as defined in the DSIs' power sales contract. Because the DSI contracts no longer include these provisions, this adjustment is not included in this study.

**Direct and Indirect Overhead Costs.** Cost of service studies and other spreadsheets prepared by the public body and cooperative customers provide information to calculate the per-unit overhead costs associated with service to large industrial consumers.

### **3. APPLICATION OF THE METHODOLOGY**

#### **3.1 Data Base**

The data base consists of cost of service information from 33 utilities that have at least one industrial consumer with a peak load of at least 3.5 MW. The data was collected in 2011 from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial consumers were deleted from the data base, and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data at the PPC offices were required to sign confidentiality agreements. All utility data reported has been identified by a randomly assigned number. Attachment 1 to this appendix displays each participating utility's individual data.

#### **3.2 Utility Margins**

The individual utility margins are based on costs allocated by the utilities to their industrial consumers. The categories of costs include production, transmission, distribution, taxes, and other overhead costs. Derivation of the margin involves three steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall weighted average margin. Third, the BPA DSI delivery facilities charge is added to replace the distribution costs that otherwise may be included in the margin.

### **3.3 Summary of Results**

The final results of each step in the industrial margin calculation for each utility are shown on the summary table in Attachment 1 to this appendix. These results were used in the BP-12 rate case. As shown on the summary table, the weighted industrial margin for the BP-12 rate case was 0.685 mills/kWh.

### **4. THE INDUSTRIAL MARGIN FOR THE BP-26 RATE CASE**

BPA did not conduct a new industrial margin survey for the BP-26 rate case. Instead, the industrial margin is escalated for inflation between the start of the BP-12 rate period and the start of the BP-26 rate period. The escalation factor uses the GDP Implicit Price Deflator using actuals from the Bureau of Economic Analysis and forecast from IHS Markit. Accordingly, the BP-12 industrial margin, 0.685 mills/kWh, is multiplied by 1.41. The BP-26 industrial margin is 0.966 mills/kWh.

## Summary - 2012 Margin Study Results

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Taxes	Weighted Margin
1	51,410,428					\$ 5.67		0.017
2	1,581,923,558					\$ 0.04		0.004
3	95,688,000	\$ 47.66	\$ 36.62	\$ -	\$ 9.38	\$ 0.45	\$ 1.21	0.002
5	42,823,202	\$ 57.46	\$ 36.78	\$ 0.85	\$ 18.61	\$ 0.42	\$ 0.80	0.001
6	29,114,880	\$ 43.02	\$ 34.50	\$ 2.36	\$ 2.87	\$ 0.72	\$ 2.57	0.001
7	40,694,000					\$ -		0.000
8	405,668,000					\$ -		0.000
9	361,407,000	\$ 4.78	\$ 3.84	\$ 0.01	\$ 0.72	\$ 0.07	\$ 0.13	0.002
11	467,121,000	\$ 45.11	\$ 32.63	\$ 5.45	\$ 3.18	\$ 0.81	\$ 3.04	0.022
12	248,035,470	\$ 36.22	\$ 34.20	\$ 0.25	\$ 1.36	\$ 0.00	\$ 0.38	0.000
13	119,932,734	\$ 38.94	\$ 36.80	\$ -	\$ 0.04	\$ 0.01	\$ 2.09	0.000
14	61,910,899	\$ 10.77	\$ -	\$ 0.47	\$ 9.79	\$ 0.51	\$ -	0.002
15	966,012,620					\$ 0.02		0.001
16	169,040,000					\$ 0.47		0.005
17	352,800,436	\$ 41.45	\$ 30.46	\$ 0.23	\$ 10.69	\$ 0.06	\$ -	0.001
18	5,390,158,000	\$ 49.42	\$ 40.45	\$ 0.90	\$ 6.60	\$ 0.88	\$ 0.58	0.273
20	297,405,000					\$ 0.15		0.003
21	340,000,000					\$ 0.43		0.008
23	78,758,000	\$ 43.69	\$ 33.49	\$ 0.12	\$ 8.23	\$ 1.11	\$ 0.74	0.005
24	203,423,478	\$ 62.26	\$ 33.19	\$ 4.05	\$ 22.70	\$ 0.10	\$ 2.22	0.001
25	152,608,000	\$ 40.67	\$ 31.32	\$ 0.77	\$ 4.29	\$ 3.40	\$ 0.89	0.030
26	47,700,000	\$ 46.82	\$ 34.17	\$ 0.85	\$ 10.86	\$ 0.32	\$ 0.62	0.001
27	15,897,484					\$ 0.32		0.000
28	3,022,602,000					\$ 0.54		0.093
29	718,303,000					\$ 0.35		0.015
30	808,561,000	\$ 51.24	\$ 47.77	\$ 0.14	\$ 0.30	\$ 0.04	\$ 2.99	0.002
31	223,878,000	\$ 36.86	\$ 29.79	\$ -	\$ 5.86	\$ 0.71	\$ 0.49	0.009
32	750,395,000	\$ 54.12	\$ 44.55	\$ 2.13	\$ 0.15	\$ 4.19	\$ 3.10	0.180
33	194,837,000	\$ 46.71	\$ 39.37	\$ -	\$ 4.53	\$ 0.01	\$ 2.81	0.000
34	21,884,198					\$ 5.29		0.007
35	94,165,000	\$ 26.69	\$ 7.06	\$ 0.66	\$ 15.48	\$ 0.03	\$ 3.47	0.000
36	19,516,800					\$ 0.03		0.000
37	38,909,777					\$ 0.01		0.000
<b>Total:</b>	<b>17,412,583,964</b>							<b>0.685</b>

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## Utility Number: # 1

Two industrial customers; rates set through contract.

Customer 1: BPA rate plus \$1.09/MWh; 2009 sales (kWh)	=		<b>31,485,920</b>
Margin	=	\$	<b>34,320</b>
Customer 2: BPA rate plus \$21,430/mo; 2009 sales	=		<b>19,924,508</b>
Margin	=	\$	<b>257,160</b>
Total margin from Customers 1 & 2	=	\$	<b>291,480</b>
Sales to Customers 1 & 2 (kWh)	=		<b>51,410,428</b>

## Utility Number: # 2

Large Industrial includes sales under Schedules 14, 15, & 16

	<u>Ave # of customers</u>	<u>Load (kWh)</u>	<u>Monthly basic charge</u>
Schedule 14	3	123,852,000	\$ 200
Schedule 15	6	1,223,870,998	\$ 500
Schedule 16	10	<u>234,200,560</u>	\$ 200
		<u>1,581,923,558</u>	
Total basic charges/year =			<u>\$ 67,200</u>

Utility Number: # 3							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	\$ 3,503,816	\$ 3,503,816					\$ 3,503,816
Transmission:	\$ -						
Distribution:	\$ 66,980			\$ 66,980			\$ 66,980
Customer Accounts:	\$ 20,315				\$ 20,315		\$ 20,315
Customer Services:	\$ 4,599				\$ 4,599		\$ 4,599
Admin & Genl:	\$ 68,093			\$ 49,632	\$ 18,461		\$ 68,093
Taxes:	\$ 115,384					\$ 115,384	\$ 115,384
Depreciation:	\$ 779,001			\$ 779,001			\$ 779,001
Interest:	\$ 2,352			\$ 2,352			\$ 2,352
<b>TOTAL</b>	<b>\$ 4,560,540</b>	<b>\$ 3,503,816</b>		<b>\$ 897,965</b>	<b>\$ 43,375</b>	<b>\$ 115,384</b>	<b>\$ 4,560,540</b>

Utility Number: # 5							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	\$ 1,574,999	\$ 1,574,999					\$ 1,574,999
Transmission:	\$ 14,196		\$ 14,196				\$ 14,196
Distribution:	\$ 310,053			\$ 310,053			\$ 310,053
Customer Accounts:	\$ 7,316				\$ 7,316		\$ 7,316
Meter Reading:	\$ 194			\$ 194.00			\$ 194
Customer Service:	\$ 3,456				\$ 3,456		\$ 3,456
Sales Exp:	\$ 2,549				\$ 2,549		\$ 2,549
Admin & Genl (1):	\$ 120,230		\$ 5,056	\$ 110,429	\$ 4,744		\$ 120,230
Depreciation:	\$ 232,235		\$ 10,168	\$ 222,067			\$ 232,235
Taxes:	\$ 34,108					\$ 34,108	\$ 34,108
Interest:	\$ 159,676		\$ 6,991	\$ 152,685			\$ 159,676
Other:	\$ 1,731		\$ 76	\$ 1,655			\$ 1,731
<b>TOTAL</b>	<b>\$ 2,460,743</b>	<b>\$ 1,574,999</b>	<b>\$ 36,486</b>	<b>\$ 797,084</b>	<b>\$ 18,065</b>	<b>\$ 34,108</b>	<b>\$ 2,460,743</b>

<b>Utility Number: # 6</b>							
	<b>Large Industrial</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>Other</b>	<b>Taxes</b>	<b>Sum</b>
<b>Purchased Power:</b>	\$ 1,035,622	\$ 1,035,622					\$ 1,035,622
<b>Transmission:</b>	\$ 712		\$ 712	\$ -			\$ 712
<b>Distribution:</b>	\$ 59,107			\$ 59,107			\$ 59,107
<b>Meter Reading:</b>	\$ 18			\$ 18			\$ 18
<b>Customer Records &amp; Collection:</b>	\$ 54			\$ 54			\$ 54
<b>Misc Customer Service:</b>	\$ 87				\$ 87		\$ 87
<b>A &amp; G:</b>	\$ 41,855		\$ 497	\$ 41,297	\$ 61		\$ 41,855
<b>Taxes:</b>	\$ 74,851					\$ 74,851	\$ 74,851
<b>Inrerest:</b>	\$ 46,721		\$ 555	\$ 46,166			\$ 46,721
<b>Capital Projects:</b>	\$ 88,598		\$ 67,619		\$ 20,979		\$ 88,598
<b>Other Deduction (2):</b>	\$ (63,872)		\$ (758)	\$ (63,021)	\$ (93)		\$ (63,872)
<b>BPA Conservation, Con Aug, other:</b>	\$ (31,231)	\$ (31,231)					\$ (31,231)
<b>TOTAL</b>	\$ 1,252,522	\$ 1,004,391	\$ 68,625	\$ 83,621	\$ 21,034	\$ 74,851	\$ 1,252,522

## Utility Number: # 7

One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 40,694 MWh

Monthly Base Charge = \$0.00

Demand Charge = \$5.75/kW

Energy Charge = \$0.0316/kWh

**Utility Number: # 8**

One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 405,668 MWh

Monthly Base Charge = \$0.00

Industrial rates set by city ordinance

## Utility Number: # 9

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Costs:	\$ 1,387,888	\$ 1,387,888					\$ 1,387,888
Transmission:	\$ 1,320		\$ 1,320				\$ 1,320
Distribution:	\$ 71,299			\$ 71,299			\$ 71,299
Customer Accounts:	\$ 263				\$ 263		\$ 263
Public Relations & Info:	\$ 11,873				\$ 11,873		\$ 11,873
Energy Services:	\$ 3,159				\$ 3,159		\$ 3,159
Admin & Genl:	\$ 63,036		\$ 946	\$ 51,079	\$ 11,011		\$ 63,036
Depreciation:	\$ 75,872		\$ 1,379	\$ 74,493			\$ 75,872
Taxes:	\$ 48,396					\$ 48,396	\$ 48,396
Interest:	\$ 65,238		\$ 1,186	\$ 64,052			\$ 65,238
<b>TOTAL</b>	<b>\$ 1,728,344</b>	<b>\$ 1,387,888</b>	<b>\$ 4,831</b>	<b>\$ 260,923</b>	<b>\$ 26,306</b>	<b>\$ 48,396</b>	<b>\$ 1,728,344</b>

**Utility Number: # 11**

	Two Industrial Customers	Production	Transmission	Distribution	Other	Taxes	Sum
<b>Power:</b>	\$ 15,244,327	\$ 15,244,327					\$ 15,244,327
<b>Transmission:</b>	\$ 2,544,405		\$ 2,544,405				\$ 2,544,405
<b>Distribution:</b>	\$ 1,481,945			\$ 1,481,945			\$ 1,481,945
<b>Meter Reading + Cust Records:</b>	\$ 5,366			\$ 5,366			\$ 5,366
<b>Customer Education:</b>	\$ 77,324				\$ 77,324		\$ 77,324
<b>Low Income Assist.:</b>	\$ 156,540				\$ 156,540		\$ 156,540
<b>Electric Marketing:</b>	\$ 142,594				\$ 142,594		\$ 142,594
<b>Taxes:</b>	\$ 1,419,465					\$ 1,419,465	\$ 1,419,465
<b>TOTAL</b>	\$ 21,071,966	\$ 15,244,327	\$ 2,544,405	\$ 1,487,311	\$ 376,458	\$ 1,419,465	\$ 21,071,966

Utility Number: # 12							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	\$ 644,417	\$ 644,417					\$ 644,417
Purchased Power:	\$ 8,379,469	\$ 8,379,469					\$ 8,379,469
Transmission:	\$ 77,781		\$ 77,781				\$ 77,781
Distribution:	\$ 412,110			\$ 412,110			\$ 412,110
Meter Reading + Customer Records:	\$ 9,303			\$ 9,303			\$ 9,303
Customer Service:	\$ 3,113				\$ 3,113		\$ 3,113
Admin & Genl:	\$ 496,109	\$ 278,795	\$ 33,651	\$ 182,317	\$ 1,347		\$ 496,109
Taxes:	\$ 95,106					\$ 95,106	\$ 95,106
Interest:	\$ 341,788	\$ 192,595	\$ 23,246	\$ 125,947			\$ 341,788
Capital Projects:	\$ 455,818	\$ 256,850	\$ 31,002	\$ 167,966			\$ 455,818
Other Revenue:	\$ (1,931,751)	\$ (1,270,440)	\$ (103,488)	\$ (560,694)	\$ (4,142)		\$ (1,938,764)
<b>TOTAL</b>	<b>\$ 8,983,263</b>	<b>\$ 8,481,687</b>	<b>\$ 62,191</b>	<b>\$ 336,948</b>	<b>\$ 318</b>	<b>\$ 95,106</b>	<b>\$ 8,976,250</b>

<b>Utility Number: # 13</b>							
	<b>Large Industrial</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>Other</b>	<b>Taxes</b>	<b>Sum</b>
<b>Purchased Power:</b>	\$ 3,813,592	\$ 3,813,592					\$ 3,813,592
<b>Transmission</b>							
<b>Distribution</b>							
<b>Conservation</b>	\$ 600,000	\$ 600,000					\$ 600,000
<b>Meters &amp; Services</b>	\$ 4,742			\$ 4,742			\$ 4,742
<b>Accounting</b>	\$ 536				\$ 536		\$ 536
<b>Customer Related</b>	\$ 789				\$ 789		\$ 789
<b>Revenue Related</b>	\$ 250,374					\$ 250,374	\$ 250,374
<b>TOTAL</b>	\$ 4,670,033	\$ 4,413,592		\$ 4,742	\$ 1,325	\$ 250,374	\$ 4,670,033

## Utility Number # 14

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
<b>Production:</b>	\$ -						
<b>Transmission:</b>	\$ 29,120		\$ 29,120				\$ 29,120
<b>Distribution:</b>	\$ 560,614			\$ 560,614			\$ 560,614
<b>Metering &amp; Billing:</b>	\$ 45,398			\$ 45,398			\$ 45,398
<b>Customer Services:</b>	\$ 31,565				\$ 31,565		\$ 31,565
<b>TOTAL</b>	\$ 666,697		\$ 29,120	\$ 606,012	\$ 31,565		\$ 666,697

**Utility Number: # 15**

7 customers in High Voltage General rate class; load = 966,012,620 kWh

Customer Charge per meter per month = \$ **210**

Total customer charges per year = \$ **17,640**

**Utility Number: # 16**

1 large industrial customer with peak of at least 3.5 aMW

Total Industrial sales in 2009 = 169,040 MWh

Fixed charge (equivalent to customer charge of \$6,557/month; annual cost = \$ 78,684

<b>Utility Number: # 17</b>							
	<b>Industrial</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>Other</b>	<b>Taxes</b>	<b>Sum</b>
<b>Purchased Power:</b>	\$ 10,747,941	\$ 10,747,941					\$ 10,747,941
<b>Transmission:</b>	\$ 15,940		\$ 15,940				\$ 15,940
<b>Distribution:</b>	\$ 735,733			\$ 735,733			\$ 735,733
<b>Customer Accnts:</b>	\$ 4,917				\$ 4,917		\$ 4,917
<b>Customer Svcs:</b>	\$ 1,963				\$ 1,963		\$ 1,963
<b>Interest on Debt (2):</b>	\$ 398,427		\$ 8,449	\$ 389,978			\$ 398,427
<b>Depreciation (2):</b>	\$ 551,528		\$ 11,696	\$ 539,832			\$ 551,528
<b>Additional revenue req.:</b>	\$ 2,165,398		\$ 45,621	\$ 2,105,704	\$ 14,073		\$ 2,165,398
<b>TOTAL</b>	\$ 14,621,847	\$ 10,747,941	\$ 81,706	\$ 3,771,247	\$ 20,953		\$ 14,621,847

## Utility Number: # 18

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	\$ 45,179,704	\$ 45,179,704					\$ 45,179,704
Purchased Power:	\$ 182,460,007	\$ 182,460,007					\$ 182,460,007
Conservation:	\$ 26,968,662	\$ 26,968,662					\$ 26,968,662
Transmission:	\$ 9,881,306		\$ 9,881,306				\$ 9,881,306
Distribution:	\$ 72,213,558			\$ 72,213,558			\$ 72,213,558
Customer costs:	\$ 4,980,734				\$ 4,980,734		\$ 4,980,734
Low income assistance:	\$ 4,680,598				\$ 4,680,598		\$ 4,680,598
Franchise Adjustments:	\$ 3,136,376					\$ 3,136,376	\$ 3,136,376
Revenue Credits:	\$ (83,124,365)	\$ (36,590,117)	\$ (5,011,314)	\$ (36,623,179)	\$ (4,899,754)		\$ (83,124,365)
<b>TOTAL</b>	<b>\$ 266,376,580</b>	<b>\$ 218,018,256</b>	<b>\$ 4,869,992</b>	<b>\$ 35,590,379</b>	<b>\$ 4,761,578</b>	<b>\$ 3,136,376</b>	<b>\$ 266,376,580</b>

**Utility Number: # 20**

2 large industrial customers with peak of at least 3.5 aMW

Total Industrial sales in 2009 = 297,405 MWh

Margin charges = 0.0195 cents/kWh for first 19.1 aMW in a month, and 0.0098 cents for each kWh thereafter

167,316,000 kWh at 0.0195 cents

130,089,000 kWh at 0.0098 cents

Total margin charges for 2009 = **4,537,534** cents = \$ **45,375**

**Utility Number: # 21**

Industrial sales in 2010 = 340,000 MWh

Industrial customers in 2010 = 35

Customer cost per month in 2010 = **\$349**

Total customer cost = **\$146,639**

<b>Utility Number: # 23</b>							
	<b>Industrial</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>Other</b>	<b>Taxes</b>	<b>Sum</b>
<b>Purchased Power:</b>	\$ 2,626,334	\$ 2,626,334					\$ 2,626,334
<b>Transmission:</b>							
<b>Distribution:</b>	\$ 318,070			\$ 318,070			\$ 318,070
<b>Customer Services &amp; Accts:</b>	\$ 63,752			\$ 9,575	\$ 54,177		\$ 63,752
<b>A &amp; G:</b>	\$ 155,355	\$ 11,293		\$ 130,111	\$ 13,951		\$ 155,355
<b>Depreciation:</b>	\$ 141,272		\$ 9,761	\$ 112,513	\$ 18,998		\$ 141,272
<b>Interest:</b>	\$ 77,847			\$ 77,847			\$ 77,847
<b>Taxes:</b>	\$ 58,569					\$ 58,569	\$ 58,569
<b>TOTAL</b>	<b>\$3,441,199</b>	<b>\$2,637,627</b>	<b>\$9,761</b>	<b>\$648,116</b>	<b>\$87,126</b>	<b>\$58,569</b>	<b>\$3,441,199</b>

## Utility Number: # 24

	(includes NLSL)	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	\$ 6,752,558	\$ 6,752,558					\$ 6,752,558
Transmission:	\$ 414,702		\$ 414,702				\$ 414,702
Distribution:	\$ 2,326,532			\$ 2,326,532			\$ 2,326,532
Customer Related:	\$ 19,242				\$ 19,242		\$ 19,242
A & G:	\$ 448,614		\$ 67,395	\$ 378,092	\$ 3,127		\$ 448,614
Depr & Amort:	\$ 939,205		\$ 142,086	\$ 797,119			\$ 939,205
Taxes:	\$ 451,195					\$ 451,195	\$ 451,195
Interest:	\$ 1,347,794		\$ 203,898	\$ 1,143,896			\$ 1,347,794
Capital Requirements:	\$ 232,129		\$ 35,117	\$ 197,011			\$ 232,129
Other Income:	\$ (267,290)		\$ (40,154)	\$ (225,272)	\$ (1,863)		\$ (267,290)
<b>TOTAL</b>	<b>\$ 12,664,681</b>	<b>\$ 6,752,558</b>	<b>\$ 823,043</b>	<b>\$ 4,617,379</b>	<b>\$ 20,506</b>	<b>\$ 451,195</b>	<b>\$ 12,664,681</b>

## Utility Number: # 25

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	\$ 4,780,364	\$ 4,780,364					\$ 4,780,364
Transmission:	\$ 69,374		\$ 69,374				\$ 69,374
Distribution:	\$ 393,197			\$ 393,197			\$ 393,197
Customer Related:	\$ 1,729				\$ 1,729		\$ 1,729
A & G:							
Prop ins/inj & damag:	\$ 17,112			\$ 17,112			\$ 17,112
Cust acct/serv & info/sales rel:	\$ 480,913				\$ 480,913		\$ 480,913
Depreciation:	\$ 328,871	\$ 18	\$ 48,211	\$ 244,836	\$ 35,806		\$ 328,871
Taxes:	\$ 135,572					\$ 135,572	\$ 135,572
<b>TOTAL</b>	<b>\$ 6,207,132</b>	<b>\$ 4,780,382</b>	<b>\$ 117,585</b>	<b>\$ 655,145</b>	<b>\$ 518,448</b>	<b>\$ 135,572</b>	<b>\$ 6,207,132</b>

## Utility Number: # 26

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	\$ 1,629,832	\$ 1,629,832					\$ 1,629,832
Transmission:	\$ 12,295		\$ 12,295				\$ 12,295
Distribution:	\$ 150,666			\$ 150,666			\$ 150,666
Customer Related:							
Meter reading & cust. Records:	\$ 6,440			\$ 6,440			\$ 6,440
Customer sales & service:	\$ 7,343				\$ 7,343		\$ 7,343
Depreciation:	\$ 129,443		\$ 9,395	\$ 120,048			\$ 129,443
A & G + Other Expense:	\$ 185,637		\$ 12,914	\$ 165,011	\$ 7,712		\$ 185,637
Taxes:	\$ 29,545					\$ 29,545	\$ 29,545
Interest:	\$ 74,929		\$ 5,438	\$ 69,491			\$ 74,929
Other Expenses:	\$ 7,009		\$ 506	\$ 6,200	\$ 302		\$ 7,008
<b>TOTAL</b>	<b>\$2,233,139</b>	<b>\$1,629,832</b>	<b>\$40,548</b>	<b>\$517,856</b>	<b>\$15,357</b>	<b>\$29,545</b>	<b>\$2,233,138</b>

**Utility Number: # 27**

Utility # 27 has 1 large industrial customer; 2009 load = **15,897,484 kWh**

Customer cost per month in 2010 = **\$ 418.70**

**Total customer cost = \$ 5,024.40**

**Utility Number: # 28**

**Utility # 28 has 3 large industrial customers; 2009 load = 3,022,602,000 kWh**

**Margin charges set in contract with each customer; total margin charges in 2009 = \$1,619,690**

**Utility Number: # 29**

1 large industrial customer; 2009 load = 718,303 MWh

Direct costs of contract administration for this customer (2 plants)	=	\$ 175,442
		<u>\$ 79,376</u>
		<b>\$ 254,818</b>

## Utility Number: # 30

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	\$ 42,669,341	\$ 42,669,341					\$ 42,669,341
Transmission:	\$ -		\$ -				\$ -
Distribution:	\$ 322,009			\$ 322,009			\$ 322,009
Meter reading + customer records:	\$ 2,429			\$ 2,429			\$ 2,429
Customer related:	\$ 1,301				\$ 1,301		\$ 1,301
A & G:	\$ 260,302			\$ 259,262	\$ 1,040		\$ 260,302
Taxes:	\$ 2,418,041					\$ 2,418,041	\$ 2,418,041
Interest:	\$ 673,382			\$ 673,382			\$ 673,382
Capital Projects:	\$ 290,096		\$ 110,346	\$ 145,596	\$ 34,154		\$ 290,096
Other Revenues:	\$ (5,209,277)	\$ (4,047,303)		\$ (1,157,333)	\$ (4,641)		\$ (5,209,277)
<b>TOTAL</b>	<b>\$ 41,427,624</b>	<b>\$ 38,622,038</b>	<b>\$ 110,346</b>	<b>\$ 245,345</b>	<b>\$ 31,854</b>	<b>\$ 2,418,041</b>	<b>\$ 41,427,624</b>

## Utility Number: # 31

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production	\$ 6,669,764	\$ 6,669,764					\$ 6,669,764
Transmission							
Fixed Oper Costs (Distn)	\$ 406,590			\$ 406,590			\$ 406,590
on Oper Exp (Cust Svc & Acct)	\$ 71,114				\$ 71,114		\$ 71,114
Admin & Bus Exp	\$ 530,588			\$ 442,017	\$ 88,571		\$ 530,588
Taxes	\$ 110,812					\$ 110,812	\$ 110,812
LTGO Debt Servd & Cap	\$ 462,840			\$ 462,840			\$ 462,840
<b>TOTAL</b>	<b>\$ 8,251,708</b>	<b>\$ 6,669,764</b>	<b>\$ -</b>	<b>\$ 1,311,447</b>	<b>\$ 159,685</b>	<b>\$ 110,812</b>	<b>\$ 8,251,708</b>

## Utility Number: # 32

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	\$ 33,760,238	\$ 33,760,238					\$ 33,760,238
Transmission:	\$ 145,001		\$ 145,001				\$ 145,001
Distribution:	\$ 10,066			\$ 10,066			\$ 10,066
Customer Services & Accounts:	\$ 2,171,387				\$ 2,171,387		\$ 2,171,387
A & G:	\$ 989,157		\$ 61,651	\$ 4,280	\$ 923,226		\$ 989,157
Capital Projects:	\$ 1,151,312		\$ 1,076,576	\$ 74,736			\$ 1,151,312
Debt Service:	\$ 333,697		\$ 312,035	\$ 21,662			\$ 333,697
Direct Assignments:	\$ 1,442,631		\$ 89,915	\$ 6,242	\$ 1,346,474		\$ 1,442,631
Other Revenue:	\$ (1,721,861)	\$ (329,663)	\$ (86,749)	\$ (6,022)	\$ (1,299,426)		\$ (1,721,860)
Taxes:	\$ 2,329,920					\$ 2,329,920	\$ 2,329,920
<b>TOTAL</b>	<b>\$ 40,611,548</b>	<b>\$ 33,430,575</b>	<b>\$ 1,598,429</b>	<b>\$ 110,963</b>	<b>\$ 3,141,661</b>	<b>\$ 2,329,920</b>	<b>\$ 40,611,549</b>

## Utility Number: # 33

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	\$ 7,378,831	\$ 7,378,831					\$ 7,378,831
Conservation:	\$ 134,032	\$ 134,032					\$ 134,032
Distribution:	\$ 161,203			\$ 161,203			\$ 161,203
Customer Related:	\$ 714				\$ 714		\$ 714
A & G:	\$ 398,772	\$ 180,599		\$ 217,211	\$ 962		\$ 398,772
Broad Band:	\$ 93,962	\$ 42,554		\$ 51,181	\$ 227		\$ 93,962
Interest:	\$ 531,746			\$ 531,746			\$ 531,746
Cash Flow:	\$ 495,596	\$ 224,450		\$ 269,950	\$ 1,196		\$ 495,596
Taxes:	\$ 547,357					\$ 547,357	\$ 547,357
Other Revenue:	\$ (640,934)	\$ (290,272)		\$ (349,116)	\$ (1,546)		\$ (640,934)
<b>TOTAL</b>	<b>\$ 9,101,279</b>	<b>\$ 7,670,195</b>	<b>\$ -</b>	<b>\$ 882,175</b>	<b>\$ 1,552</b>	<b>\$ 547,357</b>	<b>\$ 9,101,279</b>

**Utility Number: # 34**

1 large industrial customer with peak of at least 3.5 aMW

2008 Industrial load = 21,884,198 kWh

Margin = \$.00529/kWh

Total margin charges for 2008 =     **\$    115,767**

## Utility Number: # 35

	Total Utility	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Production:	\$ 2,477,820	\$ 318,447	\$ 318,447					\$ 318,447
Transmission:	\$ 428,864	\$ 55,117		\$ 55,117				\$ 55,117
Distribution:	\$ 4,226,132	\$ 543,138			\$ 543,138			\$ 543,138
Metering Reading:	\$ 571,769	\$ 73,483			\$ 73,483			\$ 73,483
Credit & Billing:	\$ 853,653	\$ 109,711			\$ 109,711			\$ 109,711
Information & Advertising:	\$ 52,530	\$ 6,751				\$ 6,751		\$ 6,751
Administrative & General Expenses:	\$ 4,598,604	\$ 591,008	\$ 170,068	\$ 29,435	\$ 387,900	\$ 3,605		\$ 591,008
Taxes:	\$ 2,541,360	\$ 326,613					\$ 326,613	\$ 326,613
Debt Service:	\$ 7,940,000	\$ 1,020,441	\$ 295,443	\$ 51,135	\$ 673,863			\$ 1,020,441
Capital Projects:	\$ 6,280,000	\$ 807,100	\$ 233,675	\$ 40,445	\$ 532,980			\$ 807,100
Total Transfers:	\$ 841,720	\$ 108,177	\$ 31,320	\$ 5,421	\$ 71,436			\$ 108,177
Energy Sales:	\$ (9,248,760)	\$ (1,188,642)	\$ (342,042)	\$ (59,201)	\$ (780,148)	\$ (7,251)		\$ (1,188,642)
Other Revenues:	\$ (2,006,586)	\$ (257,885)	\$ (41,976)	\$ (60,458)	\$ (155,087)	\$ (363)		\$ (257,884)
<b>TOTAL</b>	<b>\$ 19,557,106</b>	<b>\$ 2,513,460</b>	<b>\$ 664,935</b>	<b>\$ 61,895</b>	<b>\$ 1,457,276</b>	<b>\$ 2,742</b>	<b>\$ 326,613</b>	<b>\$ 2,513,461</b>

**Utility Number: # 36**

1 large industrial customer; 2008 load = 19,516,800 kWh

Monthly Customer Charge = **\$51.37**      Total charges =    \$    **616.44**

**Utility Number: # 37**

1 large industrial customer; 2010 load = 38,909,777 kWh

Customer charge = **\$208**



