

BP-24 Rate Proceeding

Final Proposal

# Power Rates Study

BP-24-FS-BPA-01

July 2023





# POWER RATES STUDY

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## COMMONLY USED ACRONYMS AND SHORT FORMS

|            |                                                            |
|------------|------------------------------------------------------------|
| AAC        | 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<br>River Power System (FCRPS) Biological Opinion (BiOp) |
| NLSL           | New Large Single Load                                                                                             |
| NMFS           | National Marine Fisheries Service                                                                                 |
| NOAA Fisheries | National Oceanographic and Atmospheric Administration<br>Fisheries                                                |
| NOB            | Nevada-Oregon border                                                                                              |
| NORM           | Non-Operating Risk Model (computer model)                                                                         |
| NWPA           | Northwest Power Act/Pacific Northwest Electric Power<br>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

The 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) 2024 and 2025.

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

- The Power Revenue Requirement Study, BP-24-FS-BPA-02, and its accompanying Documentation, BP-24-FS-BPA-02A, provide information regarding the power revenue requirement. *See* Power Revenue Requirement Study, § 2.5.
- The Power Loads and Resources Study, BP-24-FS-BPA-03, and its accompanying Documentation, BP-24-FS-BPA-03A, provide load and resource forecasts.
- The Power Market Price Study and Documentation, BP-24-FS-BPA-04, provide 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-24-FS-BPA-05, and its accompanying Documentation, BP-24-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 Treasury Payment Probability (TPP) standard of 95 percent. The Risk Study  
3 includes quantitative and qualitative analyses of financial risks and tools for  
4 mitigating those risks, including those required by BPA's Financial Reserves Policy  
5 (FRP). Administrator's Record of Decision, Financial Reserves Policy Phase-In  
6 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-24-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-24-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 (§ 2.1 below), and establishes a set of rate directives  
12 that provide further guidance on how individual rates are to be derived (§ 2.2 below).  
13 *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  
22 advance sale of surplus energy based on the generation shape of the Federal system; and  
23 (2) firm requirements power under a Block product. The costs associated with the energy  
24 and capacity necessary to provide this service are recovered through Tier 1 rate charges  
25 for 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 2024-2025 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 § 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 2024-2025 rate period was completed in August 2022. BPA  
24 engaged customers in a public process from May to August 2022, with two public comment  
25 periods and two public workshops. After completion of the review and comment periods,  
26 BPA examined the information collected. BPA posted its determination of values for the

1 FY 2024-2025 rate period for RHWM Tier 1 System Capability, including RHWM  
2 Augmentation; each customer's RHWM; and each customer's Above-RHWM Load. *See* Rate  
3 Period High Water Mark Process, [https://www.bpa.gov/energy-and-services/rate-and-](https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/rate-period-high-water-mark-process)  
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, RHWMs 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 GRSPs discussed in Sections 4 and 5. At a high level, BPA's ratemaking  
13 process for power products and services has three main steps:

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

24  
25 Section 6 discusses Transfer Service. More than half of BPA's power customers are served  
26 by the transmission systems of third parties (entities other than BPA). Under the Regional

1 Dialogue contracts, BPA must acquire transmission services from these third-party  
2 transmission providers to deliver Federal power to BPA's power customers. This third-  
3 party transmission service is commonly referred to as transfer service. Transfer service  
4 customers may be subject to one or more separate charges from BPA.

5  
6 Section 7 discusses the Slice True-Up. Slice customers are subject to an annual Slice  
7 True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the  
8 Composite cost pool and to the Slice cost pool. BPA calculates the annual Slice True-Up  
9 Adjustment for each fiscal year as soon as BPA's audited actual financial data are available.

10  
11 Section 8 discusses Average System Costs. The Residential Exchange Program (REP),  
12 established by Section 5(c) of the Northwest Power Act, was designed to provide  
13 residential and farm customers of Pacific Northwest utilities a form of access to low-cost  
14 Federal power. 16 U.S.C. § 839c(c). Under the REP, BPA purchases power from each  
15 participating utility at that utility's average system cost (ASC). ASCs – stated in dollars per  
16 megawatthour (\$/MWh) or mills per kilowatthour (mills/kWh) – are determined by BPA  
17 in separate processes occurring outside the BP-24 rate proceeding for each utility  
18 participating in the REP.

19  
20 Section 9 discusses BPA's revenue forecast. The revenue forecast calculates the expected  
21 revenue from power rates and other sources for the rate period, FY 2024-2025, and the  
22 current year, FY 2023. BPA prepares two revenue forecasts, one using rates from the rate  
23 schedules currently in effect (BP-22 rates) and the second using BP-24 rates. The revenue  
24 forecasts are used to test whether current rates and revised rates will recover the power  
25 revenue requirement.

1 **2. RATEMAKING COST OF SERVICE AND RATE DIRECTIVES STEPS**

2  
3 **2.1 Cost of Service Analysis**

4 **2.1.1 Statutory Background**

5 Northwest Power Act Sections 7(b), 7(d), 7(f), and 7(g) direct how BPA allocates resource  
6 and other costs to load (rate) pools. 16 U.S.C. §§ 839e(b), 839e(d), 839e(f), 839e(g). This  
7 allocation is performed in the Rate Analysis Model for the BP-24 rate period (RAM2024).

8  
9 Section 7(b)(1) states:

10 The Administrator shall establish a rate or rates of general application for  
11 electric power sold to meet the general requirements of public body,  
12 cooperative, and Federal agency customers within the Pacific Northwest, and  
13 loads of electric utilities under Section 5(c) of this title. Such rate or rates shall  
14 recover the costs of that portion of the Federal base system resources needed  
15 to supply such loads until such sales exceed the Federal base system resources.  
16 Thereafter, such rate or rates shall recover the cost of additional electric  
17 power as needed to supply such loads, first from the electric power acquired  
18 by the Administrator under Section 5(c) of this title and then from other  
19 resources.  
20

21 16 U.S.C. § 839e(b)(1). Section 7(b)(1) thus describes how BPA is to allocate resource costs  
22 to meet the general requirements of public body, cooperative, and Federal agency  
23 customers within the Pacific Northwest and the loads of electric utilities participating in  
24 the REP under § 5(c), collectively called the Priority Firm Power (PF) customer class. *Id.*  
25 At this initial stage of the ratemaking process, the PF rate pool consists of the loads of  
26 public bodies and cooperatives (collectively identified as preference customers in  
27 Northwest Power Act § 5(b)), Federal agency loads, and the loads of REP-participating  
28 utilities.

29  
30 Section 7(b)(1) requires that Federal base system (FBS) resources be used to serve the  
31 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

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

16  
17 Section 7(f) states:

18 Rates for all other firm power sold by the Administrator for use in the Pacific  
19 Northwest shall be based upon the cost of the portions of Federal base system  
20 resources, purchases of power under Section 5(c) of this title and additional  
21 resources which, in the determination of the Administrator, are applicable to  
22 such sales.  
23

24 *Id.* § 839e(f). Section 7(f) prescribes how costs are allocated to rates for all other firm  
25 power after costs are allocated to the PF rate pool and the rates for BPA's direct-service  
26 industrial customers (DSIs) are determined. *Id.* Section 7(f) allocates the remaining  
27 exchange and new resource costs to the remaining regional load (power sold at the New  
28 Resource Firm Power (NR) rate and the Firm Power and Surplus Products and Services  
29 (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 2024 Rate Analysis Model (RAM2024)  
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-24-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

1 Northwest Power Act, and when Section 7 does not provide guidance, they are based on  
2 general principles of cost causation. The COSA then categorizes costs, determined in the  
3 Power Revenue Requirement Study, BP-24-FS-BPA-02, and revenue credits, determined in  
4 the Power and Transmission Risk Study, BP-24-FS-BPA-05, as well as Section 2.1.6 below,  
5 into cost pools. The COSA concludes by using the EAFs to apportion these costs and  
6 revenue credits among the rate pools. Sections 2.1.3 through 2.1.7 below provide more  
7 detail.

### 9 **2.1.3 Loads and Resources**

10 The COSA uses disaggregated customer load data from the source data used to produce the  
11 Power Loads and Resources Study, BP-24-FS-BPA-03. *See* Power Rates Study  
12 Documentation, BP-24-FS-BPA-01A, Table 2.1.1. The disaggregated load data are  
13 aggregated into the PF rate pool (consisting of two sub-pools, the PF Public (PFp) rate pool  
14 and the PF Exchange (PFx) rate pool), the Industrial Firm Power (IP) rate pool, the New  
15 Resource Firm Power (NR) rate pool, and the FPS rate pool. *Id.*, Table 2.2.2.1.

16  
17 The COSA also uses the disaggregated resource data from the source data in the Power  
18 Loads and Resources Study. *Id.*, Table 2.1.2. The disaggregated resource data are  
19 aggregated into the resource pools specified by Section 7 of the Northwest Power Act.  
20 16 U.S.C. § 839e. These resource pools are the FBS resource pool, the exchange resource  
21 pool, and the new resource pool. *Id.*, Table 2.2.2.1. The resources in the FBS and new  
22 resource pools are actual or planned resources that are forecast to be able to serve load  
23 during the rate period. The ratemaking process requires that the forecast firm resources  
24 available to serve load equal BPA's firm load obligations under critical water conditions.  
25 Critical water conditions assume very low streamflow conditions based on the historical

1 record along with today's generating facilities and constraints to yield an amount of energy  
2 output.

### 3 4 **2.1.3.1 Load Pools**

5 Load pools are groupings of forecast sales into customer classes for cost allocation  
6 purposes. These load pools are used to create rate pools. The Northwest Power Act  
7 establishes three rate pools based on the loads served at particular rates. The 7(b) rate  
8 pool includes sales to public body and cooperative customers (consumer-owned utilities or  
9 COUs), Federal agencies, and utilities participating in the REP. 16 U.S.C. § 839e(b). The  
10 7(c) rate pool includes sales to BPA's DSI customers under contracts authorized by  
11 Section 5(d) of the Northwest Power Act. *Id.* § 839e(c). The 7(f) rate pool includes three  
12 types of sales: (1) power sold to consumer-owned utilities which is determined to serve  
13 NLSLs; (2) Section 5(b) requirements power sold to the region's investor-owned utilities  
14 (IOUs); and (3) power sold by BPA pursuant to Section 5(f) of the Northwest Power Act. *Id.*  
15 § 839e(f).

16  
17 The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any  
18 resource costs to the IP rate pool; rather, the IP rate is set using a formula pursuant to  
19 Section 7(c). *Id.* § 839e(c). The formula ties the IP rate to the PF rate. However, if DSI  
20 loads were excluded from cost allocations, loads and resources would be out of balance,  
21 leaving an amount of resource costs not allocated to any loads. Therefore, for ratemaking  
22 purposes BPA allocates resource costs to IP loads as it does to all other remaining firm  
23 power sold. The result is that BPA has, for all practical purposes, only two rate pools, the  
24 7(b) rate pool and all other loads. The resource cost allocations to the IP rate pool are  
25 adjusted later in the Rate Directives Step to conform the IP rate to the statute-based  
26 formula.

1 **2.1.3.2 Resource Pools**

2 The three resource pools are Federal base system resources, exchange resources, and new  
3 resources.

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

14  
15 To implement the direction in Northwest Power Act Section 5(c)(1) that BPA is to purchase  
16 resources from each eligible REP participant and sell an equivalent amount of electric  
17 power to each participant, the exchange resources are sized to be equal to the forecast of  
18 the eligible REP exchange load during the rate period. *Id.* § 839c(c)(1). To calculate the  
19 eligible REP exchange load, the COSA determines whether the potential exchanging utilities  
20 have ASCs that are greater than the applicable base Pfx change rate for the rate period.  
21 Utilities with ASCs higher than the base Pfx rate are assumed to participate in the REP  
22 during the rate period. In this way, BPA estimates the Pfx load, the size of the exchange  
23 resource pool, and the costs of the exchange resources (the ASCs multiplied by the eligible  
24 exchange loads). *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.1.3.  
25 This process is iterative and dependent upon the outcomes of the Rate Directives Step.  
26 *See* § 2.2.2 below. As part of the BP-24 rates settlement process, BPA and REP-utilities

1 agreed to a condensed ASC Review Process in order to finalize FY 2024-2025 ASCs prior to  
2 publication of the BP-24 Initial Proposal. *See* Principles of Settlement for the BP-24 Rate  
3 Proceeding, FY 2024-2025 Average System Cost Process, and the FY 2022 Power Reserves  
4 Distribution Clause Process (BP-24 Settlement Agreement), Fredrickson *et. al.*, BP-24-FS-  
5 BPA-09, Appendix A, Attachment 1.

6  
7 Exchange resources are set equal to the amount of resulting qualifying exchange load,  
8 which implements the direction in Section 5(c)(1) that BPA is to purchase power from each  
9 eligible REP participant and sell an equivalent amount of electric power to each participant.  
10 16 U.S.C. § 839c(c)(1).

11  
12 The new resources pool includes all other resources acquired by BPA unless a resource has  
13 been determined to be a replacement for reduced FBS capability.

### 14 15 **2.1.3.3 Order of Resource Service to Load Pools**

16 Section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated  
17 to the PF customer class. *Id.* § 839e(b)(1). FBS resources are used to serve the PF rate pool  
18 until FBS resources are exhausted, whereupon exchange resources and then, if required,  
19 new resources are used to serve remaining PF rate load. Section 7(f) of the Northwest  
20 Power Act specifies what and how costs are allocated to “all other firm power” after costs  
21 are allocated to the PF rate pool: the remaining exchange and new resources costs are  
22 allocated to remaining load. *Id.* § 839e(f). That remaining load is served under IP, NR, and  
23 FPS contracts.

24  
25 For the BP-24 rates, the PF load (which includes both PFp and PFx loads) exceeds the  
26 capability of the FBS resources. Therefore, all FBS costs and benefits are allocated to the

1 PF rate pool. A pro rata share of exchange resource costs is allocated to the PF rate pool in  
2 an amount necessary for the exchange resources to serve the PF load not served by FBS  
3 resources. The costs of any remaining exchange resources and all new resources are  
4 allocated to all other firm load, with a small fraction of new resources serving PF load if  
5 necessary. *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.5.4.*

#### 7 **2.1.3.4 Load and Resource Adjustments**

8 The Power Loads and Resources Study includes a forecast of the generating capability of all  
9 resources available to BPA to serve its load obligations. Ratemaking uses only the amount  
10 of resources available to serve the rate pool loads; thus, some adjustments must be made.  
11 BPA has certain system obligations, including the Canadian Entitlement and U.S. Bureau of  
12 Reclamation (Reclamation) pumping loads (together called FBS obligations), that have  
13 existed since before the passage of the Northwest Power Act. *See Treaty between Canada  
14 and the United States of America relating to the Cooperative Development of the Water  
15 Resources of the Columbia River Basin (Columbia River Treaty), Art. VI 4(b), Jan. 17, 1961,  
16 15 U.S.T. 1555, 542 U.N.T.S. 244.* FBS resources used to serve these system obligations are  
17 taken “off the top,” removing both the obligation and a corresponding amount of FBS  
18 resource before the ratemaking load-resource balance is calculated.

19  
20 The ratemaking load-resource balance after adjustments is shown in Power Rates Study  
21 Documentation, BP-24-FS-BPA-01A, Tables 2.2.2.1-2.

#### 23 **2.1.3.5 Energy Allocation Factors**

24 The aggregated load and resource data are used to calculate EAFs that the COSA uses to  
25 apportion costs among rate pools. EAFs are calculated for each resource and rate pool  
26 combination by dividing the amount of annual energy load in each rate pool by the amount

1 served from each resource pool. The annual EAFs for each resource cost pool and for the  
2 rate directive steps are shown in Tables 2.2.3.1-2. *Id.* The General and Conservation  
3 allocation factors assume a pro rata allocation of costs to all firm loads. For example, the  
4 General and Conservation (“Total Usage”) EAFs are used to allocate some Section 7(g) costs  
5 and rate directive allocation adjustments to all firm energy loads.

#### 7 **2.1.4 Ratemaking Costs**

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

11  
12 Functionalization of costs between the generation and transmission functions (BPA does  
13 not have a distribution function normal to most utilities) is reflected in the Power Revenue  
14 Requirement Study, BP-24-FS-BPA-02, and the Transmission Revenue Requirement Study,  
15 BP-24-FS-BPA-06. The costs functionalized to the generation function are included in the  
16 power revenue requirement found in the COSA. An exception is exchange resource costs  
17 (*see* § 2.1.4.2 below). The exchange resource costs are calculated internal to RAM2024.  
18 The exchange resource costs include transmission function costs. The exchange resource  
19 costs are functionalized in the COSA modeling so that only the generation portion of the  
20 exchange resource costs is subject to the power cost rate steps, and the transmission cost  
21 portion is then added back in after the Rate Directives Step is completed. *See* Power Rates  
22 Study Documentation, BP-24-FS-BPA-01A, Table 2.3.4.2. In this way, the statutorily  
23 mandated power cost relationships between the various rate pools are maintained without  
24 being affected by the transmission function costs of the exchange.

1 The COSA modeling uses other costs that are internally generated by RAM2024. These  
2 include exchange resource costs, some power purchase costs, revenue shortfall costs  
3 associated with some rate credits, and revenues from secondary power sales. These are  
4 covered in greater detail below.

#### 6 **2.1.4.1 Revenue Requirement**

7 The revenue requirement from the Power Revenue Requirement Study is supplemented in  
8 the COSA for costs that are determined in other steps of the ratemaking process (such as  
9 projected balancing purchase power costs; system augmentation costs; PNRR, if any; and  
10 the functionalized exchange resource costs). Disaggregated costs are listed in a form  
11 consistent with the income statement from the Power Revenue Requirement Study and are  
12 shown in Table 2.3.1.1-5. *Id.* RAM2024 uses unique identifier key codes to categorize these  
13 costs to the COSA cost pools. *Id.*, Table 2.3.2.

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

- 18  
19 1. **Purchased Power.** The purchased power subset of purchased power costs includes  
20 the costs of acquisition of power through renewable energy, wind, geothermal, and  
21 competitive acquisition programs. Costs of purchased power from the Power  
22 Revenue Requirement Study are included in the new resources pool.
- 23 2. **System Augmentation.** For ratemaking purposes, it may be assumed that BPA  
24 acquires resources beyond the inventory represented by the system generating  
25 resources and balancing power purchases if loads exceed resources under critical  
26 water year assumptions. *See* Power Loads and Resources Study, BP-24-FS-BPA-03,



1 § 4.2. System augmentation amounts are determined in the Power Loads and  
2 Resources Study and are used to meet annual customer firm power loads in excess  
3 of annual firm system resources. The mean price from the Critical Water Run is  
4 used to value the cost of system augmentation. *See* Power and Transmission Risk  
5 Study, BP-24-FS-BPA-05, § 3.1.2.1.1. System augmentation purchases are treated as  
6 FBS replacements and, as such, the costs are included in and allocated as FBS costs.  
7 *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

8 **3. Balancing Power Purchases.** The costs of power purchases and storage required  
9 to meet firm deficits on a monthly/diurnal basis are included in the category of  
10 balancing power purchases. Projected balancing power purchases are generally  
11 needed to serve firm loads in months other than the spring fish migration period  
12 under some water conditions. Balancing purchase expenses are calculated for each  
13 monthly/diurnal period where BPA is energy deficit across all 2,700 iterations in  
14 the Revenue Simulation Model (RevSim). The median purchasing price and quantity  
15 associated with these purchases for each year of the rate period are passed to  
16 RAM2024 to compute balancing purchase costs. *See* Power and Transmission Risk  
17 Study, BP-24-FS-BPA-05, § 3.1.2.1. Balancing power purchases are treated as FBS  
18 replacements and, as such, the costs are included in and allocated as FBS costs. *See*  
19 Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

#### 21 **2.1.4.2 Functionalization of Exchange Resource Costs**

22 In the COSA, exchange resource costs are based on participating utilities' ASCs and their  
23 exchange power sales to BPA. Each utility's ASC includes the cost of power and  
24 transmission services associated with serving the utility's TRL. By definition, exchange  
25 resource sales to BPA equal the exchange sales by BPA. The rate directive adjustments that  
26 occur subsequent to the COSA use the results of the COSA allocations of the generation

1 revenue requirement. Therefore, because the exchange resource costs in the COSA include  
2 transmission costs, the PFX rate includes a transmission cost adder, and the exchange  
3 resource costs are functionalized between power and transmission.

4  
5 The exchange resource costs functionalized to power continue through the ratemaking  
6 process. The exchange resource costs functionalized to transmission are removed from the  
7 generation revenue requirement for the Rate Directives Step and are added back to  
8 determine the PFX rate after the Rate Directives Step is completed. In this way, the  
9 exchange resource costs functionalized to power are treated the same as other power  
10 function costs through the rate development process. The transmission function costs are  
11 collected directly from PFX loads through a transmission adder included in the PFX rate.  
12 Because the amount of exchange resource costs functionalized to transmission is equal to  
13 the increased revenue due to the PFX rate adder, there is no net cost to other rates due to  
14 these transmission costs. The functionalization of exchange resource costs is shown in  
15 Table 2.3.4.2. *Id.*

### 16 17 **2.1.4.3 Low Density Discount**

18 Section 7(d)(1) of the Northwest Power Act instructs BPA to apply a Low Density Discount  
19 (LDD) to mitigate the costs of customers with relatively fewer consumers spread over  
20 relatively larger geographic areas. 16 U.S.C. § 839e(d)(1). *See* Power Rate Schedules and  
21 General Rate Schedule Provisions (GRSPs), BP-24-A-02-AP01, GRSP II.B.

22  
23 The cost of providing the discount is computed in RAM2024 using offset quantities and the  
24 internally computed TRM rates. Offset quantities are the sum of the applicable LDD  
25 percentages applied to the customer-specific billing determinants. *See* TRM, BP-12-A-03,

1 § 10.2. These offsets are computed in the TRM Billing Determinants Model, which is a  
2 module of RAM2024.

3  
4 The estimated cost of the LDD is shown in Power Rates Study Documentation, BP-24-FS-  
5 BPA-01A, Table 2.3.3.1. The entire cost of the discount is allocated to the PF load pool prior  
6 to linking the IP rate to the PF rate. *Id.*, Table 2.3.4.1.

#### 7 8 **2.1.4.4 Irrigation Rate Discount**

9 A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and  
10 the TRM. The discount is a rate, expressed in mills per kilowatthour (kWh), that when  
11 applied to qualified irrigation load produces a dollar credit on eligible customers' power  
12 bills. *See* Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.C. The Irrigation  
13 Rate Discount (IRD) rate is calculated in RAM2024, as described in Section 5.4.2 below.  
14 The cost of the discount is computed in RAM2024 using contract irrigation loads and the  
15 internally calculated rate. The entire cost of the IRD is allocated to the PF load pool prior to  
16 linking the IP rate to the PF rate.

#### 17 18 **2.1.5 Cost Pools**

19 The COSA has six cost pools for the initial allocation of BPA's power costs: FBS resource  
20 costs, exchange resource costs, new resource costs, conservation costs, BPA program costs,  
21 and power transmission costs. These costs are allocated to the rate pools using direction  
22 from Sections 7(b)(1), 7(f), and 7(g) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(1),  
23 839e(f), 839e(g).

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

2 Section 7(b)(1) costs are associated with the resource cost pools necessary to serve  
3 PF load, including the PFp load and the PFx load. 16 U.S.C. § 839e(b)(1). For the BP-24  
4 rates, these resources include all of the FBS resources and all of the exchange resources.  
5 Therefore, all FBS resource costs and all exchange resource costs are Section 7(b)(1) costs  
6 allocated to serve Section 7(b)(1) loads. Costs associated with the LDD under Section 7(d)  
7 and the IRD are allocated along with Section 7(b)(1) costs.

8  
9 **2.1.5.2 Section 7(f) Costs**

10 Section 7(f) costs are associated with the resource cost pools necessary to serve non-PF  
11 load, including IP, NR, and FPS loads. *Id.* § 839e(f). For the BP-24 rates, these resources  
12 include most of the new resources. Therefore, most new resource costs are Section 7(f)  
13 costs allocated to serve all remaining loads; that is, IP, NR, and FPS loads.

14  
15 **2.1.5.3 Section 7(g) Costs**

16 **Conservation Costs.** The Northwest Power Act requires BPA to treat cost-effective  
17 conservation savings as a resource in planning to meet the Administrator’s obligations to  
18 serve loads. The “conservation” line item, as seen in Power Rates Study Documentation,  
19 BP-24-FS-BPA-01A, Tables 2.3.1.1-5, includes (1) amortization of BPA’s previous  
20 conservation resource acquisition activities; (2) BPA’s continuing contributions to the  
21 region’s market transformation efforts; (3) costs associated with BPA’s energy efficiency  
22 business; and (4) a share of Net Revenues (Minimum Required Net Revenues (MRNR) plus  
23 PNRR, if any). Conservation costs are allocated to all rate pools using the Conservation  
24 EAFs. *Id.*, Table 2.3.4.3.

1 **BPA Program Costs.** Some of BPA's program costs are not identified directly with any  
2 specific resource pool. An example is the cost of tracking and implementing national  
3 energy policies and initiatives. Development of these power program costs occurs in the  
4 Integrated Program Review (IPR), as described in Power Revenue Requirement Study,  
5 BP-24-FS-BPA-02, Section 2.1. The power portion appears in the COSA as BPA program  
6 costs. BPA program costs are allocated to all rate pools based on the Total Usage EAFs.  
7 *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.3.4.3.

8  
9 **BPA Power Transmission Costs.** Power transmission expenses include the costs of  
10 serving customers under Transfer Service. *See* § 6 below. They also include the costs  
11 Power Services incurs to procure transmission and ancillary services to transmit surplus  
12 Federal power to purchasers that do not hold transmission contracts, primarily outside the  
13 Pacific Northwest. BPA also has Federal generation that exists in third-party service  
14 territories; both wheeling costs and financial payments to cover losses are included in this  
15 category of costs. Finally, it includes an FCRPS generation-integration cost. Transmission  
16 costs are allocated to all rate pools based on the Total Usage EAFs. *Id.*, Table 2.3.4.3.

#### 17 18 **2.1.5.4 Planned Net Revenues for Risk**

19 PNRR is an amount of net revenues required to be recovered from power rates to ensure  
20 that cash flows from such rates are sufficient to meet BPA's TPP Standard. *See* Power and  
21 Transmission Risk Study, BP-24-FS-BPA-05, § 2.3. PNRR may also include an amount of  
22 additional revenue to build financial reserves under the FRP. Power and Transmission  
23 Risk Study, BP-24-FS-BPA-05, Appendix A (FRP), § 4.2.

24  
25 Under the ratemaking methodology, the amount of PNRR (if any) needed to meet the TPP  
26 Standard is the result of an iterative process among several models: RAM2024, RevSim,

1 the Power Non-Operating Risk Model (P-NORM), and ToolKit. *See* Power and Transmission  
2 Risk Study, BP-24-FS-BPA-05, § 4. The iteration is initiated with a seed value of \$0 for  
3 PNRR in the Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 2.3.1.4 and  
4 2.3.2. The resulting rates are used in RevSim to produce net revenue probability  
5 distributions. These net revenue distributions are then used in the ToolKit to test whether  
6 TPP is at least 95 percent. If not, the ToolKit produces a new PNRR value that just meets  
7 the TPP standard, rates are recalculated, a new distribution of net revenues is created, and  
8 TPP is calculated for the new distribution. The iterations are stopped when the smallest  
9 value of PNRR that meets the TPP standard has been determined. *Id.*, Table 2.3.1.4.  
10 Because no PNRR was required to meet the TPP Standard in the BP-24 rates, no iterative  
11 process was necessary. No PNRR was required in the BP-24 rates for liquidity purposes  
12 because any accrual of additional cash reserves required by the FRP is to be collected  
13 through a separate proposed surcharge. *See* § 5.2.3 below. However, PNRR was included  
14 in BP-24 rates consistent with terms of the BP-24 Settlement Agreement, Fredrickson *et al.*,  
15 BP-24-FS-BPA-09, Appendix A.

#### 16 17 **2.1.6 Revenue Credits**

18 In addition to allocating cost data, the COSA allocates various revenue credits that offset  
19 costs in each pool. Allocation of revenue credits follows the same principles as the  
20 allocation of costs, based upon statutory guidance. For example, some revenue credits are  
21 associated with the operation of FBS resources and reduce FBS resource costs to be  
22 recovered by PF rates. Some revenue credits reduce the new resource and conservation  
23 costs. Other revenue credits that are not associated with any particular cost pool are  
24 allocated to rate pools pro rata to load.

1 **2.1.6.1 Downstream Benefits and Pumping Power Revenues**

2 Downstream benefits and pumping power revenues are described in Section 9.2 below.

3 Downstream benefits and pumping power revenues are associated with FBS resources, and  
4 these credits are allocated to the same loads to which FBS costs are allocated. *See Power*  
5 *Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.3.6.*

6  
7 **2.1.6.2 Section 4(h)(10)(C) Credits**

8 Section 4(h)(10)(C) credits are described in Section 9.4.1. The forecast credit is calculated  
9 as described in the Power and Transmission Risk Study, Section 4.1, and supplied to  
10 RAM2024. Section 4(h)(10)(C) credits are associated with FBS resources, and the credits  
11 are allocated to the same loads to which FBS costs are allocated. *Id.*

12  
13 **2.1.6.3 FBS Contract Obligations Revenue**

14 BPA has certain FBS system obligations that provide revenues. For the BP-24 period, this  
15 includes only Upper Baker revenues for energy and capacity purchased by Puget Sound  
16 Energy to enable flood control elevation levels at that project. These FBS system obligation  
17 revenues are allocated to the same loads to which FBS costs are allocated. *Id.*

18  
19 **2.1.6.4 Colville Credit**

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

23  
24 **2.1.6.5 Energy Efficiency Revenues**

25 The Energy Efficiency revenue credit reflects revenues associated with the activities of  
26 BPA's Energy Efficiency program. These revenues are generally payments for

1 reimbursable expenditures that are included in the generation revenue requirement. The  
2 Energy Efficiency revenue credit is allocated in the same way as BPA’s conservation  
3 expenses and effectively reduces the amount of those expenses allocated to power rates.  
4 *Id.* The Energy Efficiency revenue credit concludes after FY 2023 upon termination of the  
5 Energy Efficiency Development Program.

#### 6 7 **2.1.6.6 Miscellaneous Revenues**

8 Miscellaneous revenues are described in Section 9.2 below. These revenues are allocated  
9 to all firm load through the Total Usage EAFs. *Id.*

#### 10 11 **2.1.6.7 Renewable Energy Certificates**

12 Revenues result from BPA’s sales of Renewable Energy Certificates (RECs). For  
13 FY 2024-2025, no revenues are expected, and the forecast is zero. *Id.*

#### 14 15 **2.1.6.8 General Revenue Credits**

16 In the course of marketing power, Power Services generates transmission-related revenues  
17 and credits. The revenues and credits are predominantly revenues associated with  
18 providing reserves and energy for ancillary services, control area services, and other  
19 reliability needs. *See* § 9.3 below. In addition to revenues associated with generation  
20 inputs, Real Power Losses (Non-Slice), PRSC Net Credits (Non-Slice), PRSC Net Credit  
21 (Composite), revenues from PF Load Forecast Deviation Liquidated Damages, Energy  
22 Shaping Service products for NLSL service, New Resource Flattening Service, and Resource  
23 Support Services for non-Federal resources are allocated to all loads through the Total  
24 Usage EAFs. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 2.3.7.5  
25 and 2.3.7.6.



1 **2.1.6.9 Secondary Energy Revenue Credits**

2 The Secondary Energy Revenue Credit adjustment recognizes that BPA collects revenues  
3 from certain power sales to which costs are not allocated. BPA credits these revenues to  
4 classes of service served with firm Federal power.

5  
6 The ratemaking process ensures that the forecast of firm resources available to serve load  
7 is equal to BPA's firm load obligations under critical water conditions. However, if firm  
8 load obligations exceed firm resources, a system augmentation purchase is assumed to  
9 achieve load-resource balance. If firm resources exceed firm load obligations, a firm  
10 surplus secondary sale is assumed to achieve load-resource balance. System Augmentation  
11 expenses are included as FBS replacements in the COSA. *See* § 2.1.4.1 above. Firm Surplus  
12 Secondary Sales are included in the secondary revenue credit calculation but allocated in  
13 the Surplus Power Sales Revenue Deficiency/Surplus Reallocation. *See* § 2.1.7 below.

14  
15 Non-firm secondary sales recognize that better than critical water conditions will most  
16 likely occur. Generation from water in excess of critical water conditions is called  
17 secondary energy. The projected secondary energy revenue credits are included so that  
18 power rates are set at a level such that revenues from all sources do not recover more than  
19 the total Power Services revenue requirement.

20  
21 The sales of secondary energy in excess of firm obligations on a monthly/diurnal basis  
22 under 2,700 games of different risk conditions are calculated by RevSim. Power and  
23 Transmission Risk Study, BP-24-FS-BPA-05, § 4.1.1; *see also* Power Rates Study  
24 Documentation, BP-24-FS-BPA-01A, Table 2.3.8. Mean prices and quantities of these  
25 secondary sales, as well as mean market prices, are passed to RAM2024 for the purposes of  
26 the secondary revenue credit and the computation of the load shaping rates.

1 The quantity of secondary sales are valued at expected wholesale market prices in the  
2 Northwest at the Mid-Columbia (Mid-C) trading hub. However, BPA makes transactions  
3 outside the Northwest. The incremental value of extra-regional sales are computed in  
4 RevSim and passed to RAM2024 as an aggregate dollar value to be included in the  
5 secondary revenue credit, after accounting for both transmission availability and regional  
6 price differences. Power and Transmission Risk Study, BP-24-FS-BPA-05, § 4.1.1.2.3; *see*  
7 *also* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.3.8. For the BP-24 rate  
8 period, value associated with market participation in the Energy Imbalance Market (EIM) is  
9 estimated by simulating EIM dispatch using forecast hourly Northwest market prices at  
10 Mid-C and projected BPA system flexibility gained by no longer holding non-reg balancing  
11 reserves. This value is directly input into RAM2024. Power Rates Study Documentation,  
12 BP-24-FS-BPA-01A, Table 3.1.1.3.

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

### 23 24 **2.1.7 Surplus Power Sales Revenue Deficiency/Surplus Reallocation**

25 BPA sells surplus firm power under the FPS rate schedule. If BPA anticipates firm  
26 generation to exceed firm load obligations on an annual average basis, Firm Surplus

1 Secondary Sales are included as a revenue credit. The COSA includes the quantity of these  
2 sales in the FPS rate pool and allocates costs to these sales. Sales of such firm power are  
3 not necessarily made at rates that recover the exact costs allocated in the COSA to these  
4 sales. Therefore, either a revenue surplus or a revenue deficiency will result when the  
5 costs allocated to the sales of this firm power are compared with the revenues received  
6 under the applicable contract. The expected revenue forecast from the sale of firm power  
7 and settlements, the allocated costs, and the resulting FPS revenue deficiency are shown in  
8 *id.*, Table 2.3.9. This revenue deficiency is allocated to all other firm power (PF, IP, and NR)  
9 rates.

10  
11 This is the final step of the COSA. At this point, all of BPA's costs have been allocated to the  
12 PF, IP, NR, and FPS rate pools, as have all revenues derived from sources other than these  
13 rate pools. After completion of the COSA, certain statutory reallocations of these COSA-  
14 allocated costs are performed in the Rate Directives Step.

## 15 16 **2.2 Rate Directives Step**

### 17 **2.2.1 Statutory Background**

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

23  
24 Section 7(c), in pertinent part, states:

25       The rate or rates applicable to direct service industrial customers shall be  
26       established for the period beginning July 1, 1985, at a level which the  
27       Administrator determines to be equitable in relation to the retail rates

1 charged by the public body and cooperative customers to their industrial  
2 consumers in the region.  
3

4 16 U.S.C. § 839e(c). Section 7(c) describes how BPA is to set the rate it charges DSI  
5 customers. *Id.* It provides that the DSI rate will be set to be equitable in relation to retail  
6 industrial rates of consumer-owned utility (COU) customers. Section 7(c) provides  
7 guidance on how to establish and modify this equitable relationship:

8 The [DSI rate] shall be based upon the Administrator’s applicable wholesale  
9 rates to such public body and cooperative customers and the typical margins  
10 included by such public body and cooperative customers in their retail  
11 industrial rates but shall take into account the comparative size and character  
12 of the loads served, the relative costs of electric capacity, energy, transmission,  
13 and related delivery facilities provided and other service provisions, and  
14 direct and indirect overhead costs, all as related to the delivery of power to  
15 industrial customers, except that the Administrator’s rates during such period  
16 shall in no event be less than the rates in effect for the contract year ending on  
17 June 30, 1985.  
18

19 *Id.* Section 7(c) speaks of the “applicable wholesale rates” to COUs plus the “typical  
20 margins” included by those customers in their retail industrial rates. *Id.* The computation  
21 of these elements of the DSI rate is discussed below in Section 2.2.2.5.1-2, Section 4.3.1.1.2,  
22 and Appendix A. Section 7(c) also requires a comparison of the DSI rate to the DSI rate in  
23 effect in 1985, as discussed in Section 2.2.2.5.4 below. *Id.*  
24

25 Finally, Section 7(c)(3) provides:

26 The Administrator shall adjust such rates to take into account the value of  
27 power system reserves made available to the Administrator through his rights  
28 to interrupt or curtail service to such direct service industrial customers.  
29

30 *Id.* § 839e(c)(3). Section 7(c)(3) thus directs that the DSI rate is to be adjusted to account  
31 for the value of power system reserves provided through contractual rights that allow BPA  
32 to restrict portions of the DSI load. This adjustment is typically made through a Value of

1 Reserves (VOR) Credit. The VOR analysis is discussed in Sections 2.2.2.5.2 and 4.3.1.1.1  
2 below.

3  
4 In summary, the result of Section 7(c) requirements is that the DSI rate is set equal to the  
5 applicable wholesale rate, plus the typical margin, minus the VOR Credit, subject to the DSI  
6 floor rate test. Because the DSI rate interacts with the PF rate and the NR rate, the three  
7 rates are determined simultaneously through a solution called the 7(c)(2) delta. The  
8 determination and application of the 7(c)(2) delta are discussed below in Sections 2.2.2.1-4  
9 and 2.2.2.5.1-4 and applied to the IP rate in Section 4.3.1.1.

10  
11 Section 7(b)(2) states:

12 After July 1, 1985, the projected amounts to be charged for firm power for the  
13 combined general requirements of public body, cooperative and Federal  
14 agency customers, exclusive of amounts charged such customers under  
15 subsection (g) of this section for the costs of conservation, resource and  
16 conservation credits, experimental resources and uncontrollable events, may  
17 not exceed in total, as determined by the Administrator, during any year after  
18 July 1, 1985, plus the ensuing four years, an amount equal to the power costs  
19 for general requirements of such customers if the Administrator assumes [five  
20 specified assumptions].  
21

22 *Id.* § 839e(b)(2). Section 7(b)(2) describes a rate test designed to ensure that preference  
23 customers' firm power rates are no higher than rates calculated using five assumptions that  
24 remove specified effects of the Northwest Power Act. *Id.* The rate test is now implemented  
25 through provisions of the 2012 Residential Exchange Program Settlement Agreement,  
26 which resolved challenges to BPA's previous implementation of Sections 7(b)(2) and  
27 7(b)(3). *See* 2012 Residential Exchange Program Settlement Agreement, Contract No.  
28 11PB-12322, REP-12-A-02A (2012 REP Settlement). The 2012 REP Settlement provides  
29 the manner by which BPA computes the amount of rate protection for preference

1 customers, and the amount of REP benefits to the IOUs, in lieu of performing the rate test  
2 every rate period.

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

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

9 16 U.S.C. § 839e(b)(3). Section 7(b)(3) directs that the cost of any rate protection afforded  
10 to preference customers arising from implementation of Section 7(b)(2) be borne by all  
11 other BPA power sales. *Id.* The rate protection does not extend to all PF customers: the  
12 public body, cooperative, and Federal agency customers receive the rate protection, but  
13 REP participants do not. Thus, to allow the cost reallocations due to the rate protection, the  
14 PF rate is bifurcated. The two resulting rates are the PF Public (PFp) rate, which receives  
15 the rate protection, and the PFX rate, which does not receive rate protection and bears its  
16 allocated share of the rate protection reallocation. The rate protection amount is collected  
17 through additional charges included in rates for all non-PF Public sales. The reallocation of  
18 rate protection costs is discussed in Section 2.2.2.3 below. The 2012 REP Settlement  
19 retains the allocation of rate protection costs to all other rates through mechanisms  
20 specified therein. *See* 2012 REP Settlement, REP-12-A-02A.

## 21 22 **2.2.2 Rate Directives Step Modeling**

23 The Rate Directives Step modeling takes as input the costs allocated to the four rate pools  
24 (PF, IP, NR, and FPS) from the COSA modeling. The Rate Directives Step adjusts these  
25 initial allocations among the PF, IP, and NR rate pools with reallocations of costs that  
26 conform to Section 7 of the Northwest Power Act. 16 U.S.C. § 839e. At this point in the

1 modeling, the allocation of costs to the FPS rate pool is equal to the expected revenues from  
2 FPS sales and will not be altered throughout the remaining ratemaking steps.

### 3 4 **2.2.2.1 First IP-PF Rate Link**

5 The IP rate for sales of power to BPA’s DSI customers is a formula rate tied to the  
6 unbifurcated PF rate (*i.e.*, the PF rate at this point in the modeling includes costs to be  
7 allocated between the PFp and PFx rate sub-pools later in the process). Also at this point in  
8 the modeling, the costs allocated to the IP and NR rate pools are equal on a per-  
9 megawatthour (MWh) basis. An adjustment is needed to set the IP rate to its proper  
10 relationship with the PF rate. That adjustment, the IP-PF Link 7(c)(2) rate adjustment,  
11 will result in the 7(c)(2) delta, thereby reducing the allocated costs to the IP rate pool and  
12 increasing the costs allocated to the PF and NR rate pools.

13  
14 The IP-PF Link adjustment sets the IP rate equal to the monthly/diurnal PFp energy rates  
15 applied to DSI Billing Determinants, plus the net industrial margin. To determine the  
16 IP rate, the model first calculates the net industrial margin by subtracting the VOR provided  
17 by sales to the DSIs from the typical industrial margin calculated in the 7(c)(2) Margin  
18 Study, Power Rates Study, BP-24-FS-BPA-01, Appendix A. *See* Power Rates Study  
19 Documentation, BP-24-FS-BPA-01A, Table 2.4.1. Monthly and diurnally PF melded rates  
20 are calculated as described in Section 4.1.3 below. *Id.*, Tables 2.4.2–3. Because the IP-PF  
21 Link calculation maintains a set relationship between the levels of the IP and PF rates for  
22 each year and simultaneously allocates costs between the two rates, and to avoid multiple  
23 iterations, RAM2024 has an algebraic formula to approximate a solution and then uses an  
24 intrinsic Excel function, “Goal Seek,” to converge on a solution for each year of the rate test  
25 period. *Id.*, Table 2.4.4.

1 After allocation of the 7(c)(2) delta in the IP-PF Link reallocation, the IP floor rate test  
2 determines if the currently calculated IP rate is below the IP rate that was in effect for the  
3 contract year ending on June 30, 1985, as required by Section 7(c)(2) of the Northwest  
4 Power Act. 16 U.S.C. § 839e(c)(2). The BP-24 IP rate at this point in the modeling is not  
5 below the IP floor rate, and no floor rate adjustment is needed.

#### 6 7 **2.2.2.2 Determination of Active Exchanging Utilities**

8 With the proper relationship between the IP rate and the unbifurcated PF rate established,  
9 the base PFX rates for the IOUs and the COUs can be calculated. The base PFX rate for the  
10 IOUs is the average unbifurcated PF rate plus a transmission adder. The base PFX rate for  
11 the COUs begins with the IOU rate and removes Tier 2 costs and loads. A test is again  
12 conducted to determine if the ASCs of the potential IOU and COU exchanging utilities are  
13 greater than the IOU and COU base PFX rates. If a utility's ASC is greater than its base PFX  
14 rate, the utility is included as an active exchanging utility.

#### 15 16 **2.2.2.3 7(b)(2) Rate Protection and 7(b)(3) Reallocations**

17 The next step is to calculate the level of rate protection due to preference customers as a  
18 result of the ASC and PFX calculation and pursuant to Section 7(b)(2) of the Northwest  
19 Power Act. 16 U.S.C. § 839e(b)(2). The rate test specified in Section 7(b)(2) of the  
20 Northwest Power Act ensures that BPA's rates for public body, cooperative, and Federal  
21 agency customers (collectively referred to as preference customers or 7(b)(2) customers)  
22 are no higher than rates calculated using specific assumptions that remove certain effects  
23 of the Northwest Power Act. *Id.* The BP-24 rates are calculated pursuant to a settlement of  
24 litigation associated with the REP and the Section 7(b)(2) rate test. *See* 2012 REP  
25 Settlement, REP-12-A-02A, at 1. The 2012 REP Settlement was evaluated for compliance



1 with, among other statutory provisions, Sections 7(b)(2) and 7(b)(3). 16 U.S.C.  
2 § 839e(b)(2)-(3).

3  
4 Rate modeling for the REP under the 2012 REP Settlement begins with total IOU REP  
5 benefits, as specified in the 2012 REP Settlement, known as Scheduled Amounts. *See Power*  
6 *Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.4.9.*

7  
8 The 2012 REP Settlement rate modeling first calculates the Unconstrained Benefits, which  
9 are the REP benefits that would be in place if there were no PFp rate protection. In such  
10 circumstance, the REP benefits for each exchanging utility would be its ASC minus its  
11 appropriate Base PFx rate multiplied by its qualified exchange load. The Unconstrained  
12 Benefits are shown in Table 2.4.10. *Id.* These Unconstrained Benefits are then used to  
13 calculate COU REP benefits, as specified in individual settlements with each eligible COU.  
14 COU REP benefits are calculated using a ratio of (1) the IOU Scheduled Amounts to (2) the  
15 total IOU Unconstrained Benefits for IOUs. This ratio is then multiplied by COU  
16 Unconstrained Benefits to derive COU REP benefits.

17  
18 The total rate protection provided to preference customers is composed of two parts. With  
19 the Unconstrained Benefits and the total IOU and COU REP benefits determined, the first  
20 part of rate protection due to preference customers is calculated as the Unconstrained  
21 Benefits minus the sum of REP benefits. The REP Settlement modeling then allocates this  
22 amount to individual REP participants. This allocation to each REP participant is divided  
23 by the exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge  
24 that is added to the appropriate Base PFx rates to produce a utility-specific PFx rate.  
25 *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.4.11.* After the utility-  
26 specific PFx rates are calculated, the utility-specific REP benefits are calculated and

1 summed after any reallocations necessary under Section 6.2 of the 2012 REP Settlement  
2 Agreement. *Id.*, Tables 2.4.11-12, which show reallocations between participating IOUs  
3 pursuant to Section 6.2 of the 2012 REP Settlement Agreement.

4  
5 A second part of rate protection, the REP Surcharge, is calculated and allocated to the IP  
6 and NR rate pools. The REP Surcharge is determined by multiplying the REP benefit costs  
7 determined above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in  
8 the 2012 REP Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the  
9 IP and NR rates and increases this historical 7(b)(3) rate surcharge in direct proportion to  
10 increases in REP Recovery Amounts relative to WP-10 REP benefit levels. The REP  
11 Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules,  
12 produces an amount of rate protection dollars. *Id.*, Table 2.4.14. This amount is allocated  
13 to the IP and NR rate pools.

14  
15 The REP Settlement rate protection allocations increase the IP, NR, and PFx rates while  
16 decreasing the PFp rate. *Id.*, Tables 2.4.13-15.

#### 17 18 **2.2.2.4 Second IP-PF Rate Link**

19 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must  
20 be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second  
21 IP-PF Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is  
22 set equal to the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. At this  
23 point in the ratemaking process, a reallocation of costs (consistent with Section 2.2.2.5  
24 below) establishes the NR rate. *Id.*, Tables 2.4.16–19.

1 **2.2.2.5 IP Rate**

2 The IP rate is calculated using directives in Sections 7(c)(1), 7(c)(2), and 7(c)(3) of the  
3 Northwest Power Act. 16 U.S.C. § 839e(c)(1)-(3). As discussed in Section 2.2.1 above,  
4 Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set  
5 “at a level which the Administrator determines to be equitable in relation to the retail rates  
6 charged by the public body and cooperative customers to their industrial consumers in the  
7 region.” *Id.* § 839e(c)(1). “Equitable in relation” pursuant to Section 7(c)(2) is defined as  
8 basing the DSI rate on BPA’s “applicable wholesale rates” to its COU customers plus the  
9 “typical margins” included by those customers in their retail industrial rates. *Id.*  
10 § 839e(c)(2). Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the  
11 value of power system reserves provided through contractual rights that allow BPA to  
12 restrict portions of the DSI load. *Id.* § 839e(c)(3). This adjustment is made through a Value  
13 of Reserves (VOR) Credit. Thus, the rate for the DSIs, the IP rate, is set equal to the  
14 applicable wholesale rate, plus the typical margin, plus the VOR Credit, subject to the DSI  
15 floor rate test and the outcome of the determination of PFp rate protection.

16  
17 **2.2.2.5.1 Applicable Wholesale Rate**

18 The applicable wholesale rate is calculated as the rate(s) at which BPA is selling power to  
19 COUs, that is, the PFp rate (for general requirements, as defined in Section 7(b)(4) of the  
20 Northwest Power Act) and the NR rate (for power used to serve NLSL). 16 U.S.C.  
21 § 839e(c)(4). The IP rate begins by being set to the average of the PF and NR rates,  
22 weighted by sales to COUs at each rate and reflecting the DSI class load factor. No sales to  
23 COUs at the NR rate are projected for this rate period.

1 **2.2.2.5.2 Typical Margin, Value of Reserves, and Net Industrial Margin**

2 As noted above, the DSI rate is set by adding the VOR Credit and typical margin to the  
3 applicable wholesale rate. The VOR Credit is calculated as described in Section 4.3.1.1.1  
4 below. The typical margin is calculated in Appendix A. The typical margin plus the VOR  
5 Credit yields the net industrial margin. *See* Power Rates Study Documentation, BP-24-FS-  
6 BPA-01A, Table 2.4.1. The net industrial margin is added to the applicable wholesale rate,  
7 and the result is multiplied by the forecast DSI load to determine the costs for the IP rate  
8 pool.

9  
10 **2.2.2.5.3 IP-PF Link 7(c)(2) Adjustment**

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

20  
21 **2.2.2.5.4 IP Floor Rate Verification**

22 Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers will  
23 not be less than the rates in effect for the contract year ending June 30, 1985 (the floor  
24 rate). 16 U.S.C. § 839e(c)(2). Accordingly, a test is performed to determine if the IP rate is  
25 at a level below the 1985 IP rate. If so, an adjustment is made that raises the IP rate to the

1 floor rate and credits other customers with the increased revenue from the DSIs. If the  
2 IP rate is set at a level above the floor rate, no floor rate adjustment is necessary.

3  
4 The first step in calculating the floor rate is to apply the IP-83 Standard rate components  
5 to rate period (FY 2024-2025) DSI Billing Determinants. The resulting revenue figure is  
6 divided by total IP rate period energy loads to arrive at an average rate in mills per  
7 kilowatthour. This rate is reduced by an Exchange Cost Adjustment and a Deferral  
8 Adjustment, which were included in the IP-83 rate but are no longer applicable. Both  
9 adjustments are made on a mills-per-kWh basis.

10  
11 In addition, the transmission component of the IP-83 rate is removed to allow a power-only  
12 floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total  
13 transmission costs in mills per kilowatthour from the IP-83 rate in the same manner as the  
14 Exchange Cost Adjustment and Deferral Adjustment are removed. The unit transmission  
15 component is determined by dividing total transmission costs in the IP-83 rate by the total  
16 energy billing determinants for that rate period. *See Power Rates Study Documentation,*  
17 *BP-24-FS-BPA-01A, Table 2.4.6.*

18  
19 These calculations result in an “undelivered” IP floor rate. The floor rate is applied to the  
20 current rate period DSI Billing Determinants to determine floor rate revenue. Revenue at  
21 the IP rates is compared to the revenue at the floor rate. Because revenue from the IP rate  
22 is greater than the floor rate revenue, no floor rate adjustment is necessary. *Id.,*  
23 *Tables 2.4.6-7.*

1 **2.3 Rate Modeling Iterations**

2 Several iterations – both within RAM2024 and between other models and RAM2024 – 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* § 2.2.2.2 above). RAM2024 uses a macro loop feature to test whether, for each  
16 year of the exchange period, each utility with an ASC qualifies for REP benefits. If a utility  
17 does not qualify, a binary index is used to exclude it, and if it does qualify, the index is set to  
18 include it. This test is performed such that the exchange resource costs are calculated  
19 including the resources purchased from only REP-active participants. It is performed  
20 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, RAM2024 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 **2.3.1.3 Contract Formula Rates**

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

### 16 **2.3.2 Iterations External to the Model**

17 Some aspects of the ratemaking process are dependent upon the rates computed in  
18 RAM2024. Many of these dependencies have been integrated within RAM2024, as  
19 described above. Other dependencies are simply too large to incorporate into one model.  
20 Thus, external iterations must be performed before rates can be finalized.

#### 21 **2.3.2.1 Consumer-Owned Utility Average System Costs**

22 The ASCs of COUs participating in the REP are based in part on the cost of power purchased  
23 from BPA at rates determined in RAM2024. Moreover, the COU customer's FRP Surcharge  
24  
25  
26

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 RAM2024 and the ASC  
4 forecast model. Revised ASCs are included in RAM2024, 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 four models: RAM2024, RevSim,  
10 P-NORM, and ToolKit. See Power and Transmission Risk Study, BP-24-FS-BPA-05, § 4. The  
11 iterative process is initiated with a seed value for PNRR in the revenue requirement used in  
12 RAM2024. The resultant rates are used in RevSim and P-NORM to produce distributions of  
13 net revenues. These distributions are then used in the ToolKit to produce a new PNRR  
14 value for the RAM2024 revenue requirement that just satisfies the TPP standard. Because  
15 this portion of PNRR for the BP-24 rates is determined to be zero, no iteration is required.  
16 However, PNRR was included in BP-24 rates consistent with the terms of the BP-24  
17 Settlement Agreement, Fredrickson *et al.*, BP-24-FS-BPA-09, Appendix A.

### 18 19 **2.3.2.3 Revised Revenue Test**

20 The revised revenue test is described in the Power Revenue Requirement Study, BP-24-FS-  
21 BPA-02, Section 3.3. The revised revenue test demonstrates that the BP-24 rates are  
22 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 ratesetting 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

1 customers to encourage more efficient power usage, differentiating between the relative  
2 market values of the products and services BPA offers to its customers.

3  
4 Based on the results of the Rate Directives Step, RAM2024 designs rates for each rate pool.  
5 For the PFx rate, the IP rate, and the NR rate, the rate design from the model can be applied  
6 without further processing.

### 8 **3.2 PFp Rates**

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

16  
17 The TRM specifies that all costs and credits constituting BPA's PFp revenue requirement be  
18 allocated to one of four customer cost pools: Composite, Non-Slice, Slice, or Tier 2. The  
19 Tier 2 cost pool is further divided into Short-Term, Load Growth, and Vintage cost pools, if  
20 any sales are being forecast in those cost pools. *Id.* After reflecting the cost allocations to  
21 other rate pools, the end result of the TRM cost allocations is that the total costs allocated  
22 to the four customer charge cost pools will equal the total costs allocated to the PFp rate  
23 pool after the COSA Step and the Rate Directives Step. Thus, the TRM cost allocations  
24 neither increase nor decrease the cost allocations to the PFp rate pool after the Rate  
25 Directives Step. A mathematical proof is included in RAM2024 that shows that the revenue  
26 requirement allocated to the PFp rate pools in the COSA equals the revenue collected from

1 the seven cost pools under the PFp tiered rate design. *See* Power Rates Study  
2 Documentation, BP-24-FS-BPA-01A, Tables 3.1.7.1 and 3.1.7.2.

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

12  
13 The sections below detail the calculation of PFp rates consistent with the TRM.

### 14 15 **3.2.1 PFp Tier 1 Costs**

#### 16 **3.2.1.1 Composite Costs**

17 The Composite cost pool includes all Tier 1 costs and credits that are not otherwise  
18 allocated to the Non-Slice and Slice cost pools. The Composite cost pool forms the cost  
19 basis for the Composite Customer Charge, which is paid by all preference customers with  
20 CHWM contracts. Generally speaking, all costs associated with FBS resource costs,  
21 exchange resource costs (net of exchange program revenues), new resource costs,  
22 conservation costs, BPA program costs, and power transmission costs not otherwise  
23 allocated to the Non-Slice or Slice cost pools are allocated to the Composite cost pool. In  
24 addition to the costs from expense and capital programs (as outlined in the Power Revenue  
25 Requirement Study, BP-24-FS-BPA-02), significant ratemaking costs allocated to the  
26 Composite cost pool are as follows:

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

7 *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 3.1.1.1.*

### 9 **3.2.1.2 Non-Slice Costs**

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

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

25 *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-24 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 rates recover Resource  
15 Support Services, overhead, and other BPA costs that are not necessarily incurred solely for  
16 the purpose of serving Above-RHWL Load, but support making such sales. The initial  
17 allocation of these other costs is to either the Composite cost pool or the Non-Slice cost  
18 pool. Therefore, a portion of these other costs is allocated to Tier 2 cost pools.

19  
20 The CHWM contracts include the following Tier 2 rate alternatives: Load Growth, Vintage,  
21 and Short-Term. In FY 2024 and FY 2025, BPA will have sales of power only at the Tier 2  
22 Short-Term and Load Growth rates; therefore, there are two Tier 2 cost pools: the Short-  
23 Term cost pool and the Load Growth cost pool. *See id.*, Tables 3.5.1 and 3.5.2.

1 **3.2.2.1 Tier 2 Power Purchase Costs**

2 BPA does not have any power purchases for Tier 2 rate service for the FY 2024-2025 rate  
3 period and expects power sold at Tier 2 rates to be served with power from the FCRPS,  
4 including balancing purchases. BPA uses the Remarketing Value as a forecast forward  
5 market price to calculate the cost of unpurchased amounts of Tier 2 energy. *See* § 3.2.2.6  
6 below.

7  
8 **3.2.2.1.1 Tier 2 Real Power Losses**

9 Power purchased at Tier 2 rates is delivered power and thus must include the cost of real  
10 power losses. The cost of real power losses is calculated using the Federal transmission  
11 loss factor from the BP-22 Power Loads and Resources Study, BP-22-FS-BPA-03, Section  
12 3.1.7. The Federal transmission loss factor represents the generation loss factor and must  
13 be adjusted to calculate the equivalent loss factor at the load. The load equivalent is  
14 calculated as  $1/(1-[\text{Federal transmission loss factor}])$ , which equates to a 3.21 percent real  
15 power loss factor. The power purchase costs include the cost of energy associated with this  
16 real power loss factor.

17  
18 **3.2.2.2 Tier 2 Resource Support Services**

19 A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS  
20 Adder is calculated by dividing Power Services' scheduling costs for the rate period by the  
21 total megawatthours actually scheduled in FY 2020 and FY 2021 to produce a yearly  
22 \$/MWh value. Inputs to this calculation are shown in the Power Rates Study  
23 Documentation, BP-24-FS-BPA-01A, Table 3.4. This value is multiplied by the amount of  
24 planned Tier 2 sales in each year for each Tier 2 alternative to produce the annual cost for  
25 the TSS Cost Adder included in each cost pool for each year. The Tier 2 TSS Cost Adder is  
26 one of the credits to the Composite cost pool summed in the Resource Support Services

1 Revenue Credit. See § 3.2.3.1.3 below. The calculated costs assigned to the Tier 2 rate cost  
2 pools in each year are shown in the Power Rates Study Documentation, BP-24-FS-BPA-01A,  
3 Tables 3.5.1 and 3.5.2.

4  
5 Service at Tier 2 rates includes Transmission Curtailment Management Service (TCMS),  
6 which is a service that addresses transmission curtailment events. See § 5.6.1.5 below. To  
7 recover costs associated with TCMS, Tier 2 rates are subject to the Tier 2 Rate TCMS  
8 Adjustment, described in Section 5.4.6 below. The Tier 2 cost pools do not include any  
9 costs associated with financially flattening a resource because there are no variable, non-  
10 dispatchable resources assigned to the Tier 2 cost pools for the BP-24 rate period.

### 11 12 **3.2.2.3 Tier 2 Overhead Cost Adder**

13 Section 6.3.3 of the TRM, BP-12-A-03, describes an Overhead Cost Adder to be included as  
14 part of the Tier 2 rates. The overhead cost components used to calculate the Tier 2 Rate  
15 Overhead Cost Adder are listed in the Power Rates Study Documentation, BP-24-FS-  
16 BPA-01A, Table 3.6. The rate period total of these overhead costs is divided by BPA's total  
17 forecast of revenue-producing energy sales (PFp, IP, NR, FPS, Downstream Benefits and  
18 Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services  
19 Revenue, and Secondary sales). The result is a \$1.47/MWh adder for FY 2024 and a  
20 \$1.45/MWh adder for FY 2025. The \$/MWh value in each year is multiplied by the amount  
21 of planned sales in each year for each Tier 2 alternative to produce the Overhead Cost  
22 Adder included in each Tier 2 cost pool for each year. The Tier 2 Overhead Cost Adder  
23 provides the revenue credit to the Composite cost pool (called Tier 2 Overhead  
24 Adjustment). See § 3.2.5 below. The specific cost and sales values used in these  
25 calculations are shown in the Power Rates Study Documentation, BP-24-FS-BPA-01A,  
26 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-24-  
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 FY 2024-2025 rate period. Instead of including a  
7 discrete risk adder for the remaining power purchase needs for the Tier 2 cost pools, BPA  
8 uses the Remarketing Value as a forecast forward market price for physically delivered  
9 power. *See* § 3.2.2.6 below. The Remarketing Value is based on the average of (1) the  
10 annual firm power price as calculated for a flat block of power using the Aurora model  
11 (Figure 5 of Power Market Price Study, BP-24-FS-BPA-04), and (2) the annual average  
12 Intercontinental Exchange (ICE) forward market settlement prices. Firm power prices  
13 from Aurora inherently include a risk premium due to using a monthly 10<sup>th</sup> percentile  
14 hydro generation forecast and ICE forward market settlement prices inherently include a  
15 risk premium for locking in a power purchase well in advance of delivery. Using these  
16 prices for valuing Tier 2 power that has not been transacted for in advance helps ensure  
17 that Tier 2 rates are not subsidized by Tier 1 rates. *See* Power and Transmission Risk  
18 Study, BP-24-FS-BPA-05, § 4.3.1.

19  
20 **3.2.2.5 Reallocated Power from Remarketing**

21 When power purchased for a Tier 2 rate pool exceeds Above-RHWM Loads, BPA remarkets  
22 the excess amounts and reallocates the value of that power to other Tier 2 pools if there is a  
23 need. Similarly, BPA remarkets excess non-Federal amounts and reallocates and values  
24 that power in the same manner. The remarketing values are determined in accordance  
25 with Section 3.2.2.6 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  
3 Tier 2 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-24-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),  
16 if any.

### 17 18 **3.2.2.6 Remarketing Value**

19 The Remarketing Value is used to price any remaining power needed to serve the Tier 2  
20 cost pools (Section 3.2.2.1) and to value all forms of remarketing (Tier 2, non-Federal, and  
21 Resource Remarketing Service[RRS], Section 5.7). The Remarketing Value may differ by  
22 fiscal year. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 3.9 and 3.10.

23  
24 The definition for Remarketing Value from the 2024 Power Rate Schedules and GRSPs, BP-  
25 24-A-02-AP01, GRSP III.B.24, states:

26           The Remarketing Value is the value BPA returns to customers for remarketed  
27           Tier 2 and non-Federal energy. This value is also used to calculate the cost of

1 unpurchased amounts of Tier 2 energy. The Remarketing Value is calculated  
2 for each fiscal year as the average of (1) the annual firm power price as  
3 calculated for a flat block of power using the Aurora model used to calculate  
4 the BP-24 power rates, and (2) the average Intercontinental Exchange (ICE)  
5 Mid-C settlement prices for a flat annual block of power for the same fiscal year  
6 as reported on August 15 through August 19, 2022.

7 *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 3.10.*

### 9 **3.2.3 PFp Tier 1 Revenue Credits**

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

#### 15 **3.2.3.1 Composite Cost Pool Revenue Credits**

16 As stated in Section 3.2.1.1, the Composite cost pool includes all Tier 1 costs and credits  
17 that are not otherwise allocated to the Slice and Non-Slice cost pools. As described in  
18 Section 2.1.6, revenue credits are directly assigned to the TRM cost pool according to cost  
19 causation principles at the same time the COSA steps are completed. Significant  
20 ratemaking credits allocated to the Composite cost pool after the ratemaking steps in  
21 Section 2 are completed include revenues BPA receives from the following:

- 22 • DSI customers
- 23 • Power sales under the NR rate schedule
- 24 • Resource Support Services
- 25 • PRSC Net Credit (Composite)

1 **3.2.3.1.1 Revenues from DSI Customers**

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

4  
5 **3.2.3.1.2 Revenues from Power sales under the NR rate schedule**

6 These are forecast NR rate revenues excluding revenues associated with NR Resource  
7 Flattening Service (NRFS) and Energy Shaping Service (ESS), as described in Section 4.2  
8 below.

9  
10 **3.2.3.1.3 Revenues from Resource Support Services**

11 BPA provides Resource Support Services (RSS) and related services, which generate  
12 revenue from preference customers. *See* § 5.6 below. Revenues received from the capacity  
13 components of RSS are credited to the Composite cost pool. For transparency purposes,  
14 BPA committed in the TRM to apply the applicable RSS to resources serving system  
15 augmentation needs (currently Klondike III) and to resources supporting the Tier 2 rates, if  
16 appropriate. In these situations, the source of the RSS revenue credit to the Composite cost  
17 pool is provided through either an RSS adder to the system augmentation cost or an RSS  
18 cost allocated to a Tier 2 cost pool. Revenues provided by the energy components of RSS  
19 are credited to the Non-Slice cost pool. Unlike the capacity used to provide RSS, which  
20 operationally impacts the Slice/Block, Block, and Load Following products, the provision of  
21 RSS energy operationally impacts the Non-Slice products only (including the Block portion  
22 of the Slice/Block product).

23  
24 BPA committed in the TRM to apply RSS to resources serving RHWM Augmentation needs  
25 (*e.g.*, Klondike III). The cost of Klondike III, a wind plant, is assigned to Tier 1  
26 Augmentation in the Composite cost pool. The TRM states that RSS pricing will be used to

1 make certain Federal resource acquisitions financially equivalent to a flat block. *See* TRM,  
2 BP-12-A-03, § 8. Tier 1 Augmentation is assumed to be in the shape of an annual flat block  
3 purchase for ratemaking purposes. *See id.* § 3.5. Because Klondike III’s generation is  
4 variable and non-dispatchable, the RSS module of RAM2024 calculates a DFS capacity  
5 charge, a DFS energy charge, a Resource Shaping charge, and a TSS charge for Klondike III,  
6 and the resulting costs are allocated to the Composite cost pool. *See* Power Rates Study  
7 Documentation, BP-24-FS-BPA-01A, Table 3.11. The total annual RSS revenue credit for  
8 FY 2024-2025 is shown in Power Rates Study Documentation, BP-24-FS-BPA-01A,  
9 Table 3.2. The amounts illustrated in the Power Rates Study Documentation, BP-24-FS-  
10 BPA-01A, Tables 3.2 and 3.11 vary slightly from the amounts utilized in RAM2024. This is  
11 due to BPA receiving notification of five utilities electing to take full TSS service late in the  
12 process, after RAM2024 was updated and rates were computed.

#### 14 **3.2.3.1.4 Revenues from Liquidated Damages for PF Load Forecast Deviation**

15 The PF Load Forecast Deviation Liquidated Damages revenue credit reflects load served by  
16 non-Federal power at large industrial facilities where the customer would otherwise have  
17 an obligation to serve this load with Federal power. Liquidated damages are valued at the  
18 Load Shaping True-Up Rate (LSTUR), which is the difference between PF Tier 1 Equivalent  
19 Rates and the Load Shaping Rates (market price forecast) at the time rates are set.

20 *See* § 5.4.4 below. PF Load Forecast Deviation Liquidated Damage revenues are forecast to  
21 be zero in FY 2024 and FY 2025 as shown in the Power Rates Study Documentation, BP-24-  
22 FS-BPA-01A, Table 3.12.

#### 24 **3.2.3.2 Non-Slice Cost Pool Revenue Credits**

25 As stated in Section 3.2.1.2, the Non-Slice cost pool includes all Tier 1 costs and credits that  
26 are not otherwise allocated to the Composite and 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 as the COSA steps are completed. Significant ratemaking credits  
3 allocated to the Non-Slice cost pool after the ratemaking steps in Section 2 are completed  
4 include revenues BPA receives from the following:

- 5 • Secondary Energy (including Firm Surplus Secondary Sales)
- 6 • Load Shaping
- 7 • Demand
- 8 • Resource Shaping Charge (RSC)
- 9 • NRFS and ESS
- 10 • PRSC Net Credit (Non-Slice)
- 11 • FPS Real Power Losses

#### 12

#### 13 **3.2.3.2.1 Revenues from Secondary Energy**

14 These are revenues associated with non-firm secondary sales and Firm Surplus Secondary  
15 Sales, as calculated in the Power Market Price Study, BP-24-FS-BPA-04, but excluding  
16 secondary energy sold under the Slice product as described in Section 2.1.6.9 above.

#### 17

#### 18 **3.2.3.2.2 Revenues from Load Shaping**

19 The Load Shaping charge is designed to recover costs associated with shaping the firm  
20 output of the Tier 1 System Resources to the monthly/diurnal shape of a customer's Tier 1  
21 load. The Load Shaping charge applies to Non-Slice products, Block (including the Block  
22 portion of the Slice/Block product), and Load Following, but not the Slice portion of the  
23 Slice/Block product. As stated in Section 5.2 of the TRM, BP-12-A-03, forecast revenue  
24 from the Load Shaping charge is credited to the Non-Slice cost pool by means of the Load  
25 Shaping Revenue Credit. See § 4.1.1.3 below.

1 **3.2.3.2.3 Revenues from Demand**

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

7  
8 **3.2.3.2.4 Revenues from the Resource Shaping Charge**

9 All balancing purchase costs, either resource or load, are allocated to the Non-Slice cost  
10 pool. The RSC collects additional revenues for balancing purchase costs associated with  
11 balancing resources against a flat annual block. *See* §§ 5.6.1.2, 5.6.1.3. To pair cost  
12 allocation with revenue collection of balancing purchase costs, the forecast RSC revenue  
13 credit is applied to the Non-Slice cost pool.

14  
15 BPA committed in the TRM to apply RSC to resources serving system RHWL Augmentation  
16 needs (*e.g.*, Klondike III) and to resources supporting the Tier 2 rates in order to make  
17 these acquisitions financially equivalent to a flat block. *See* TRM, BP-12-A-03, § 8. In these  
18 situations, the source of the RSC revenue credit is provided through either an RSC adder to  
19 the system augmentation cost or an RSC adder within a Tier 2 cost pool. The forecast  
20 annual RSC revenue credit for FY 2024-2025 is shown in the Power Rates Study  
21 Documentation, BP-24-FS-BPA-01A, Table 3.2.

22  
23 **3.2.3.2.5 Revenues from NR Resource Flattening Service and Energy Shaping Service**

24 The New Resource Firm Power rate schedule includes NRFS, which is available to Load  
25 Following customers applying the actual generation output of a Specified Resource to a  
26 NLSL. *See* § 5.6.2.2. The NR rate schedule also includes the ESS, which includes a capacity

1 (demand) component. Forecast revenue from the NRFS and the capacity component of the  
2 ESS is credited to the Non-Slice cost pool by means of the NR Revenue Credit. No revenues  
3 are expected under these services in FY 2024-2025. *See Power Rates Study*  
4 *Documentation, BP-24-FS-BPA-01A, Table 2.3.6.*

### 6 **3.2.4 Rate Design Adjustments Made Between Tier 1 Cost Pools**

7 Once costs and rate design revenue credits have been balanced with the revenue  
8 requirement, additional adjustments to the PFp cost pools are made to the extent necessary  
9 to avoid cost shifts among products (Load Following, Block, and Slice/Block) and tiers  
10 (Tier 1 and Tier 2). These rate design adjustments move dollars from one cost pool to  
11 another through equal credits and debits and do not change the total revenue requirement  
12 for PFp. These rate design adjustments include three adjustments made within Tier 1 and  
13 one adjustment made between Tier 1 and Tier 2 (*see* § 3.2.5). The three types of  
14 adjustments made within Tier 1 are the (1) Transmission Loss Adjustments, (2) Firm  
15 Surplus and Secondary Adjustments from Unused RHW, and (3) Balancing Augmentation  
16 Load Adjustments. The adjustment made between Tier 1 and Tier 2 is the Tier 2 Overhead  
17 Adjustment. *See* § 3.2.5 below. The TRM allocation of these rate design adjustments is  
18 shown in the Power Rates Study Documentation, BP-24-FS-BP-01A, Tables 3.1.6.1 and  
19 3.1.6.2.

#### 21 **3.2.4.1 Transmission Loss Adjustments**

22 Transmission Loss Adjustments provide a credit to the Composite cost pool and an equal  
23 debit to the Non-Slice cost pool based on Non-Slice transmission losses. Transmission Loss  
24 Adjustments address the different accounting of transmission losses for the Slice/Block  
25 and Non-Slice products. The Non-Slice products and the Block portion of the Slice/Block  
26 product are delivered to the purchaser's load service area, while the Slice product is

1 delivered to the purchaser at BPA's generation bus bar. The cost of generating the real  
2 power losses for the transmission of Non-Slice sales is included in the Composite cost pool.  
3 Conversely, the cost of generating the real power losses for the transmission of Slice sales is  
4 borne by the purchaser.

5  
6 Transmission Loss Adjustments transfer the cost of generating the real power losses for  
7 the transmission of Non-Slice PF sales from the Composite cost pool to the Non-Slice cost  
8 pool. Transmission Loss Adjustments are calculated by multiplying the network losses  
9 associated with the Non-Slice PF products, including the Block portion of the Slice/Block  
10 product, by the average Slice and Non-Slice Tier 1 rate. *See id.* The calculation and result of  
11 the Transmission Loss Adjustments are shown in the Power Rates Study Documentation,  
12 BP-24-FS-BPA-01A, Table 3.1.3.

#### 13 14 **3.2.4.2 Firm Surplus and Secondary Adjustments from Unused RHW**

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

18  
19 Unused RHW reduces the need for system augmentation and/or increases firm power  
20 available for sale in the market. The reduced augmentation expenses and/or increased  
21 firm power market revenues are reflected in three lines on the TRM cost table:

22 (1) Augmentation, (2) Secondary Energy Credit, and (3) Balancing Purchases from RevSim.  
23 *See id.*, Tables 3.1.1.1 and 3.1.1.2. The Augmentation line is part of the Composite cost pool,  
24 and the Secondary Energy Credit and Balancing Purchases are part of the Non-Slice cost  
25 pool. To share the entire benefit of Unused RHW with all customers, the Composite and  
26 Non-Slice cost pools contain a Firm Surplus and Secondary Adjustment (from Unused



1 RHWB), which appears as a credit to the Composite cost pool and an equal and offsetting  
2 charge to the Non-Slice cost pool.

3  
4 Firm Surplus and Secondary Adjustments have two purposes. The first is to reflect the  
5 difference between the value of a flat annual block of system augmentation and the value of  
6 the Unused RHWB when the Unused RHWB displaces augmentation. The difference  
7 between a flat annual block of system augmentation and the shape of the Unused RHWB is  
8 reflected in changes in the assumed balancing purchases and associated costs. These  
9 changes in balancing purchase costs are captured in the Non-Slice cost pool. A Firm  
10 Surplus and Secondary Adjustment reallocates the change in balancing purchase costs  
11 associated with the difference in value from the Non-Slice cost pool to the Composite cost  
12 pool.

13  
14 The second purpose of Firm Surplus and Secondary Adjustments is to reflect the full value  
15 of the Unused RHWB when the Unused RHWB creates firm surplus power. The revenue  
16 associated with this change in firm surplus power related to the Unused RHWB is reflected  
17 in the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary  
18 Adjustment reallocates this change in secondary revenues associated with the Unused  
19 RHWB from the Non-Slice cost pool to the Composite cost pool.

20  
21 The value of Unused RHWB consists of portions of RHWB Augmentation, Tier 1 System  
22 Firm Critical Output, and an associated portion of secondary energy. Each of these three  
23 components is valued at its respective price: the Augmentation price for the RHWB  
24 Augmentation component; the market price (as expressed by the Load Shaping rates) for  
25 the Tier 1 System Firm Critical Output component; and the market price (as expressed by  
26 the average price received for secondary sales) for the secondary component. The value of

1 Unused RHWL (expressed in dollars per megawatthour) also will be calculated for use in  
2 the Slice True-Up of the Firm Surplus and Secondary Adjustments line item in the  
3 Composite cost pool. See *id.*, Table 3.1.2, for results and calculation of Firm Surplus and  
4 Secondary Adjustments from Unused RHWL and the dollar-per-megawatthour Slice  
5 True-Up value of Unused RHWL.

### 6 7 **3.2.4.3 Balancing Augmentation Load Adjustments**

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

14  
15 The sum total of these conditions is either a charge or credit to the Composite cost pool and  
16 an offsetting credit or charge, respectively, to the Non-Slice cost pool. See *id.*, Tables 3.1.6.1  
17 and 3.1.6.2.

#### 18 19 **3.2.4.3.1 Above-RHWL Load Forecast to be Served at Load Shaping Rates**

20 This first condition occurs when Above-RHWL Load is forecast to be served at Load  
21 Shaping rates either (1) when a Load Following customer's annual Above-RHWL Load is  
22 less than 8,760 MWh and the Load Following customer made no alternative election to  
23 serve its Above-RHWL Load, or (2) when Above-RHWL Load is determined in the RHWL  
24 Process and the load forecast is updated during the rate proceeding to reflect the forecast  
25 of a larger load. When either (1) or (2) is true and the amount of system augmentation  
26 purchases is equal to or greater than the amount of balancing augmentation load, the

1 acquisition costs attributable to supplying balancing augmentation load are included as a  
2 system augmentation expense in the Composite cost pool. The revenue from supplying  
3 balancing augmentation load is credited to the Non-Slice cost pool through the Load  
4 Shaping charge revenue credit. Without a Balancing Augmentation Load Adjustment, only  
5 Non-Slice customers would receive credits through an increased Load Shaping Charge  
6 revenue credit, but both Slice and Non-Slice customers would bear the cost of increased  
7 system augmentation expense. The Balancing Augmentation Load Adjustment corrects this  
8 situation with a credit to the Composite cost pool and an equal debit to the Non-Slice cost  
9 pool.

10  
11 This condition causes the sum of Load Shaping Billing Determinants to be positive.  
12 Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are  
13 calculated as the lesser of (1) the sum of the Load Shaping Billing Determinants for each  
14 fiscal year, or (2) the incurred system augmentation amount for each fiscal year. The result  
15 is multiplied by the augmentation price for the respective fiscal year.

#### 16 17 **3.2.4.3.2 Above-RHWM Load No Longer Forecast to Occur**

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

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

7  
8 **3.2.4.3.3 Changes to the Tier 1 System During the Applicable 7(i) Ratesetting**  
9 **Process**

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

20  
21 RevSim computes Balancing Power Purchase costs after load-resource balance has been  
22 achieved under critical water. See TRM, BP-12-A-03, § 3.3. If the Tier 1 System increases  
23 relative to the RHW process Tier 1 System output, the Non-Slice cost pool will receive a  
24 credit for this additional anticipated energy equal to the avoided System Augmentation  
25 expense due to the change. Alternatively, if the Tier 1 System decreases, the Non-Slice cost  
26 pool will be charged for the reduction in anticipated energy to the extent that the reduction

1 contributed to a higher System Augmentation expense. Equal and offsetting costs/credits  
2 are applied to the Composite cost pool. *See* Power Rates Study Documentation, BP-24-FS-  
3 BPA-01A, Tables 3.1.6.1 and 3.1.6.2.

4  
5 Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are  
6 calculated as the avoided augmentation amount for each fiscal year multiplied by the  
7 augmentation price for the respective fiscal year.

### 8 9 **3.2.5 Rate Design Adjustment Made Between Tier 1 and Tier 2 Cost Pools**

10 The Tier 2 Overhead Adjustment Credits the Composite cost pool for the overhead costs  
11 charged to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost  
12 Adder, which reflects a proportionate share of BPA's total overhead costs. *See* § 3.2.2.3  
13 above. The Tier 2 Overhead Adjustment credited to the Composite cost pool is equal to the  
14 sum of the Overhead Cost Adders charged to all of the Tier 2 cost pools. The calculation of  
15 the Tier 2 Overhead Adjustment for FY 2024-2025 is shown in the Power Rates Study  
16 Documentation, BP-24-FS-BPA-01A, Table 3.6.

### 17 18 **3.2.6 Allocation of New Costs and Credits**

19 BPA will allocate New Expenses or New Credits, as defined in the TRM, to the cost pools  
20 based on the cost allocation principles stated in Section 2 of the TRM. TRM Section 2.3  
21 states that BPA will propose an allocation of the New Expenses and New Credits, if any, to  
22 the appropriate cost pools in the next applicable Section 7(i) process. TRM, BP-12-A-03,  
23 § 2.3.

24  
25 For BP-24, BPA did not add any New Expense or New Credit line items.

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## 4. RATE SCHEDULES

BPA's power rate schedules state the applicability of each rate schedule to the products that BPA offers, the rates for the products, the billing determinants to which the rates are applied, and the sections of the GRSPs that apply to each rate schedule. The power rate schedules described in this section are presented in their entirety in the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01.

### 4.1 Priority Firm Power (PF-24) Rate

The PF-24 rate applies to sales of firm (continuously available) power to be used within the Pacific Northwest by public bodies, cooperatives, Federal agencies, and investor-owned utilities participating in the REP. The PF-24 rate schedule is available for the contract purchase of Firm Requirements Power pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). Utilities participating in the REP under Section 5(c) of the Northwest Power Act may purchase PF power pursuant to a Residential Purchase and Sale Agreement (RPSA) or Residential Exchange Program Settlement Implementation Agreement (REPSIA). 16 U.S.C. § 839c(c); *see* § 8 below.

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

#### 4.1.1 PFp Tier 1 Charges

The majority of PF Public revenue is collected from firm requirements power purchased at 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* § 5.2 below.  
9 Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments  
10 will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2024  
11 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, PF-24, § 2.1.4.

#### 12 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 (*see* § 3.2.1) by the sum of the respective forecast billing determinants, as  
19 described in Section 4.1.1.1.2 below. The quotient of that calculation is then divided by 12  
20 to yield a monthly rate per 1 percent of the applicable billing determinant.

21  
22 The resulting monthly rates are shown in Power Rates Study Documentation, BP-24-FS-  
23 BPA-01A, Table 3.1.6.3.

##### 24 25 **4.1.1.1.2 Customer Charge Billing Determinants**

26 The TOCA is the customer-specific billing determinant applied to the Composite Customer



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

5  
6 The Forecast Net Requirement and RHWMM for the individual customer and the sum of  
7 RHWMMs for all customers are expressed in average annual megawatts. The total of the  
8 RHWMMs for all customers is shown in Power Rates Study Table 1, and the sum of TOCAs  
9 used for FY 2024-2025 is shown in Power Rates Study Documentation, BP-24-FS-BPA-01A,  
10 Table 3.1.6.3.

11  
12 The Non-Slice TOCA is the customer-specific billing determinant applied to the Non-Slice  
13 Customer rate. The Non-Slice TOCA is equal to a customer's TOCA if the customer is  
14 purchasing the Load Following or Block product. The Non-Slice TOCA for customers  
15 purchasing the Slice/Block product is computed as the difference between the customer's  
16 TOCA and its Slice percentage. The forecast sum of Non-Slice TOCAs used for FY 2024-  
17 2025 is shown in *Id.*, Table 3.1.6.3.

18  
19 The Slice percentage is the customer-specific billing determinant applied to the Slice  
20 Customer rate. Initial Slice percentages appear in Exhibit J of each Slice customer's CHWM  
21 contract. These percentages can be adjusted each year pursuant to TRM Section 3.6, and  
22 the final Slice percentage is established in Exhibit K of the customer's CHWM contract.  
23 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. The Microfin model estimates the nominal all-in capital costs of a Wärtsilä  
7 18V50SG reciprocating generator with a 2024 in-service date. The all-in capital cost under  
8 these specifications is \$1,575/kW as shown in Power Rates Study Documentation, BP-24-  
9 FS-BPA-01A, Table 4.1.

10  
11 The projected debt payment on the \$1,575/kW fixed capital costs is estimated at  
12 \$80.99/kW/yr., based on a cost of debt of 3.06 percent financed over 30 years. The plant is  
13 assumed to be owned by a publicly owned utility with BPA-backed bonds. The cost of debt  
14 is from BPA's FY 2022 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. See  
15 Power Revenue Requirement Study Documentation, BP-24-FS-BPA-02A, § 6, FY 2022  
16 Interest Rate and Inflation Forecast Memorandum.

17  
18 The cost of fixed O&M included in the Demand rate calculation is obtained from the  
19 Microfin model. The calculation of the Demand rate uses the Microfin model's estimate of  
20 \$5/kW/yr. escalated to 2024 and 2025 dollars using the 2016-to-2021 average (five-year)  
21 rate of 2.28 percent calculated from Implicit Price Deflators from the U.S. Bureau of  
22 Economic Analysis. The two-year average annual cost for fixed O&M is \$6.06/kW/yr.

23  
24 Insurance and fixed fuel costs are also included in the calculation of the Demand rate. The  
25 average annual insurance cost of \$3.81/kW/yr. is calculated based on 0.25 percent of the  
26 mid-year assessed value obtained from the Council's Microfin model. The average annual

1 fixed fuel cost assumed in the Demand rate calculation is \$23.69/kW/yr. The fixed fuel cost  
2 is estimated using Microfin's lifetime average rate of 8,797 Btu/kWh applied to the average  
3 of the existing eastside and westside Pacific Northwest fixed fuel costs for the applicable  
4 fiscal year.

5  
6 The average annual expense is \$114.54/kW. This annual value is shaped into the  
7 12 months of the year using the shape of the Heavy Load Hours (HLH) Load Shaping rates,  
8 resulting in Demand rates specific to each month. *See Power Rates Study Documentation,*  
9 *BP-24-FS-BPA-01A, Table 4.1; 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01,*  
10 *PF-24, § 2.1.2.1.*

#### 11 12 **4.1.1.2.2 Demand Charge Billing Determinant**

13 The Demand Billing Determinant applies to customers purchasing the Load Following and  
14 Block with Shaping Capacity products. TRM Sections 5.3.1-5 contain a detailed explanation  
15 of how to calculate the customer-specific Demand Billing Determinant, which is only a  
16 limited portion of a customer's overall demand on BPA. TRM, BP-12-A-03. The following  
17 discussion summarizes the TRM explanation.

18  
19 Four quantities are used in calculating a PFp customer's Demand Charge Billing  
20 Determinant: (1) the Tier 1 Customer's System Peak (CSP); (2) the average amount of a  
21 customer's electric load (measured in average kilowatts) that was served at Tier 1 rates  
22 during the HLH of a month; (3) the customer's Contract Demand Quantity (CDQ, expressed  
23 in kilowatts); and (4) any applicable Super Peak Credit as specified in a customer's CHWM  
24 contract.

1 The Demand Billing Determinant is determined by measuring a customer’s CSP and then  
2 subtracting the other three quantities. The Demand Billing Determinant calculation can  
3 never result in a negative billing determinant; if the calculation results in a value less than  
4 zero, the billing determinant is deemed to be zero.

5  
6 The Tier 1 CSP is equal to a customer’s maximum Actual Hourly Tier 1 Load (measured in  
7 kilowatts) during the HLH of a month. Twelve CDQs are specified for each PFp customer in  
8 the customer’s CHWM contract.

9  
10 The Super Peak Credit is determined pursuant to a customer’s CHWM contract. If a  
11 customer does not supply the Super Peak amount listed in Section 9 of Exhibit A of its  
12 CHWM contract for any hour of the Super Peak Period, then the customer does not receive  
13 a Super Peak Credit for that month. The Super Peak Period for FY 2024-2025 is defined in  
14 the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP III.B.30.

15  
16 There are two possible adjustments that may be made to a customer’s Demand Billing  
17 Determinant. The first is an adjustment to offset anomalous recovery load peaks that occur  
18 after a customer has had power restored to its service territory following a weather-related  
19 system outage or other extreme peak event. The second is an adjustment to offset extreme  
20 load changes that have severely and adversely affected a customer’s load factor. The 2024  
21 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.D, include the calculations for  
22 applying these adjustments, applicable qualifying criteria, and notice requirements. See  
23 § 5.4.3 below for more information regarding this adjustment.

1 **4.1.1.3 Tier 1 Load Shaping Charge**

2 **4.1.1.3.1 Load Shaping Charge Rates**

3 The PFp rate design includes 24 Load Shaping rates (two diurnal periods – HLH and LLH –  
4 for each of 12 months). The Load Shaping rates are set equal to the rate period average  
5 marginal cost of power for each monthly/diurnal period as determined in the Power  
6 Market Price Study and Documentation, BP-24-FS-BPA-04, § 2.4. *See also* Power Rates  
7 Study Documentation, BP-24-FS-BPA-01A, Table 4.2.

8  
9 See § 5.4.4 below for information on the Load Shaping Charge True-Up Adjustment.

10  
11 **4.1.1.3.2 Load Shaping Charge Billing Determinant**

12 The billing determinant for the Load Shaping charge is the difference between (1) a  
13 customer’s actual load served at Tier 1 rates and (2) the System Shaped Load, which is the  
14 customer’s annual load reshaped into the monthly/diurnal shape of RHWMTier 1 System  
15 Capability. The Load Shaping Billing Determinant can have either a positive or a negative  
16 value. Pursuant to the TRM, a Load Following customer’s Above-RHWMTier 1 Load that is  
17 forecast to be less than 8,760 MWh and is not served with non-Federal resources will be  
18 served by BPA at the Load Shaping rate and is reflected in this billing determinant. *See*  
19 TRM, BP-12-A-03, § 4.3.

20  
21 A customer’s System Shaped Load is calculated as the RHWMTier 1 System Capability  
22 (*see* § 1.4.2) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the  
23 customer’s Non-Slice TOCA. The Load Shaping Billing Determinants are calculated as the  
24 amount of a customer’s actual monthly/diurnal load (measured in kilowatts) to be served  
25 at Tier 1 rates minus the customer’s System Shaped Load for the same monthly/diurnal  
26 period.

1 **4.1.1.3.3 Monthly/Diurnal RHWMTier 1 System Capability**

2 The TRM prescribes that the monthly/diurnal shape of the RHWMTier 1 System Capability  
3 will be used to compute the System Shaped Load for purposes of computing Load Shaping  
4 Billing Determinants. The System Shaped Load is not updated if the RHWMTier 1 System  
5 Capability that was determined in the RHWMTier 1 System Process is updated in the rate proceeding.  
6 The system shape is computed to be constant across both years of the rate period and is the  
7 average of each year’s respective monthly/diurnal megawatthour amount. In a rate period  
8 that does not include a leap year, there will be 24 monthly/diurnal amounts for the RHWMTier  
9 Tier 1 System Capability specified in the GRSPs. In a rate period that includes a leap year,  
10 there will be 26 amounts, with a unique value for each February to account for the  
11 additional day. See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP IIA.

12  
13 **4.1.2 PFp Tier 2 Charges**

14 Tier 2 charges (rates and billing determinants) apply to PF power purchased to meet a  
15 customer’s Above-RHWMTier 1 Load. Tier 2 charges include:

- 16 • Load Shaping Charge
- 17 • Short-Term Charge
- 18 • Load Growth Charge

19 See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, PF-24, § 2.2.

20  
21 **4.1.2.1 Tier 2 Load Shaping Charge**

22 Pursuant to the TRM, a Load Following customer’s Above-RHWMTier 1 Load that is forecast to be  
23 less than 8,760 MWh and that is not served with non-Federal resources will be served at  
24 Tier 2 rates set equal to the Load Shaping rate. For ease of ratemaking and billing, and  
25 since it would create no material difference because the rate for the two is the same, BPA  
26 does not separate the Tier 2 Load Shaping Billing Determinant from the Tier 1 Load

1 Shaping Billing Determinant. Rather, the Tier 1 Load Shaping Billing Determinant can  
2 include power purchased at Tier 1 and Tier 2 rates. See § 4.1.1.3 above.

#### 3 4 **4.1.2.2 Tier 2 Short-Term and Load Growth Charges**

5 With the exception of the Tier 2 Load Shaping Charge, Tier 2 rates are calculated in a  
6 module of RAM2024 and are summarized in Power Rates Study Documentation, BP-24-FS-  
7 BPA-01A, Table 3.5.1 and 3.5.2. Each rate is calculated by dividing the annual costs  
8 allocated to the specific Tier 2 cost pool (see § 3.2.2 above) by the billing determinants  
9 (based on the annual average megawatt load obligations, excluding real power losses, for  
10 each Tier 2 rate alternative) in that same fiscal year. Each Tier 2 rate is established to  
11 recover all of the allocated costs associated with the product. The Tier 2 rates may be  
12 adjusted under certain circumstances, as shown in PF-24, Section 7. The Tier 2 rates were  
13 set consistent with the terms of the BP-24 Settlement Agreement, Fredrickson *et al.*, BP-24-  
14 FS-BPA-09, Appendix A.

15  
16 The Tier 2 Billing Determinant is equal to each customer's commitment to purchase from  
17 BPA all or a portion of the customer's Above-RHWM Load. Each customer's Tier 2 rate  
18 service amount is contractually established for FY 2024-2025. The totals for all customers  
19 are summarized in Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 4.3.

#### 20 21 **4.1.3 PFp Melded Rates (Non-Tiered Rate)**

22 The PF Melded rate is a non-tiered rate applicable to the sale of Firm Requirements Power  
23 under contracts other than CHWM contracts. No sales under the PF Melded rate are  
24 forecast during the rate period, FY 2024-2025.

1 Melded PF Public rates are included in Section 3 of the PF rate schedule and consist of  
2 12 HLH Energy rates, 12 LLH Energy rates, and 12 Demand rates. The PFp Melded Energy  
3 rates are equal to the PFp Load Shaping rates less a scalar. The scalar is a single mills per  
4 kilowatthour value that adjusts the Load Shaping rates so that the PFp Melded Energy  
5 rates, in conjunction with the demand revenue, do not collect more or less revenue than the  
6 Tier 1 and Tier 2 revenue requirement allocated to the PFp loads. Calculation of the PFp  
7 Melded rate components, including the scalar, is shown in Power Rates Study  
8 Documentation, BP-24-FS-BPA-01A, Table 3.1.8.2. The applicable Demand rates are equal  
9 to the PFp Tier 1 Demand rates.

10  
11 The PFp Melded Energy rates are subject to risk adjustments during the Rate Period  
12 pursuant to the Power CRAC; the Power RDC; and the Power FRP Surcharge. *See* § 5.2  
13 below. Any adjustments to rates and GRSPs during the Rate Period due to such risk  
14 adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs.  
15 BP-24-A-02-AP01. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, PF-24,  
16 § 3.

#### 17 18 **4.1.4 Unanticipated Load Service Charge**

19 BPA provides Unanticipated Load Service (ULS) for Load Following customers under the  
20 PF rate schedule and provides a similar service under the NR and FPS rates. ULS is  
21 described in Section 5.10 below and in the 2024 Power Rate Schedules and GRSPs, BP-24-  
22 A-02-AP01, GRSP II.M.

#### 23 24 **4.1.5 PFp Resource Support Services Rates**

25 BPA offers RSS and related services for customers' variable, non-dispatchable non-Federal  
26 resources in accordance with the CHWM contract. In general, RSS are designed to



1 financially convert these resources into a flat annual block of power or the specified  
2 monthly/diurnal resource shape found in Exhibit A of the customer's CHWM contract.

3 RSS available under the PFp rate schedule include the following:

- 4 • DFS, as discussed in Section 5.6.1.1 below and the 2024 Power Rate Schedules and  
5 GRSPs, BP-24-A-02-AP01, GRSP II.I.1.
- 6 • Grandfathered Generation Management Service, as discussed in Section 5.6.1.7  
7 below and the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP  
8 II.I.6.
- 9 • Resource Shaping Charge, as discussed in Sections 5.6.1.2-3 below and the 2024  
10 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.I.2.
- 11 • Secondary Crediting Service (SCS), as discussed in Section 5.6.1.6 below and the  
12 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.I.3.

13  
14 The related services include Transmission Scheduling Service, Transmission Curtailment  
15 Management Service, and RRS. These related services are provided under the FPS rate  
16 schedule and are discussed in Section 4.4 below.

#### 17 18 **4.1.6 Priority Firm Exchange (PFx) Rate**

19 A utility-specific PFx rate applies to each participant in the REP for sales and purchases of  
20 exchange energy pursuant to an RPSA (for eligible consumer-owned utilities) or an REPSIA  
21 (for eligible investor-owned utilities).

22  
23 The 2012 REP Settlement (*see* § 5.12) requires that BPA pay a fixed sum of REP benefits to  
24 IOUs eligible for the REP pursuant to a schedule of payments set forth in the 2012 REP  
25 Settlement, 2012 REP Settlement, REP-12-A-02A. The yearly fixed sum is included in  
26 BPA's revenue requirement and collected in BPA's rates. Each IOU's share of the fixed

1 amount of REP benefits is determined pursuant to the calculations contained in Section 6 of  
2 the 2012 REP Settlement. In particular, Section 6.2 of the 2012 REP Settlement describes a  
3 series of adjustments BPA is required to make to certain IOUs' shares of the REP benefits.  
4 BPA's implementation of Section 6.2, including the specific calculations BPA used to reach  
5 the resulting REP allocations, is shown in Power Rates Study Documentation, BP-24-FS-  
6 BPA-01A, Table 2.4.12.

7  
8 The PFX rate has two components: (1) two common Base PFX rates (one for COUs with  
9 CHWM contracts and another for all other REP participants); and (2) utility-specific REP  
10 Surcharges. The COUs have a different Base PFX rate because the PFP rate is tiered.  
11 Neither component of the PFX rate is diurnally differentiated or contains an additional  
12 charge for demand. Each participant's ASC is a single mills/kWh rate applied to all  
13 kilowatthours. Likewise, the rate design for each participant's PFX rate is a single mills per  
14 kilowatthour rate applied to all kilowatthours.

15  
16 Base PFX rates are based on the average PF rate immediately prior to the determination of  
17 Section 7(b)(2) rate protection. The PFX rate applicable to IOUs (and any eligible COU  
18 without a CHWM contract) is computed by dividing all costs allocated to the PF rate pool by  
19 all PF rate pool loads and then adding a transmission charge for delivering the exchange  
20 power to the customer. The PFX rate applicable to COUs with CHWM contracts is calculated  
21 in the same manner, except that the costs allocated to Tier 2 cost pools are excluded from  
22 the numerator and loads served at Tier 2 rates are excluded from the denominator.

23  
24 Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of  
25 providing 7(b)(2) rate protection continues to be assessed. *See* 2012 REP Settlement,  
26 REP-12-A-02A; § 2.2.2.3 above. The amount of 7(b)(2) rate protection costs allocated to

1 the PFX rates is allocated to each IOU REP participant on a pro rata basis using REP  
2 Unconstrained Benefits calculated from the difference between utility-specific ASCs and the  
3 Base PFX rate for IOUs as the allocator. The cost of 7(b)(2) protection recovered from the  
4 7(b)(3) Surcharge applied to the PFX rate for exchanging COUs is imputed from the  
5 aggregate protection allocated to IOUs relative to the aggregate Unconstrained Benefits  
6 among the IOUs, so that exchanging COUs bear an equitable responsibility for 7(b)(2) rate  
7 protection owed to the PFP rate pool. The total amount allocated to each REP participant is  
8 divided by the participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

9  
10 For each REP participant, the applicable Base PFX rate is added to its utility-specific 7(b)(3)  
11 surcharge to determine its utility-specific PFX rate. For each month of the rate period, the  
12 participant will submit its exchange load to BPA for the prior month. Under either an RPSA  
13 or an REPSIA, a utility-specific PFX rate is applied to BPA's sales of exchange energy and the  
14 participating utility's ASC is applied to BPA's purchase of exchange energy, where the  
15 exchange energy is equal to the utility's eligible residential and farm load. The difference  
16 between the amount BPA pays for exchange "purchases" and the amount BPA receives for  
17 exchange "sales" determines the amount of monetary REP benefits BPA pays the utility.  
18 BPA will multiply this invoiced exchange load by the difference between the participant's  
19 ASC and its PFX rate to calculate the amount of REP benefits payable to the participant.

20 *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.4.11.*

## 21 22 **4.2 New Resource Firm Power (NR-24) Rate**

23 The NR-24 rate applies to sales to investor-owned utilities under Northwest Power Act  
24 Section 5(b) requirements contracts. 16 U.S.C. § 839c(b). The NR-24 rate is also applicable  
25 to sales to any public body, cooperative, or Federal agency to the extent such power is used  
26 to serve any NLSL, as defined by the Northwest Power Act, including planned NLSLs, as

1 defined in Exhibit D of a customer's CHWM contract. The NR-24 rate includes energy and  
2 demand rates.

#### 3 4 **4.2.1 NR Energy Charge**

5 Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and  
6 LLH differentiation of the PFp Load Shaping rates. *See* Power Rates Study Documentation,  
7 BP-24-FS-BPA-01A, Table 3.1.8.4. The NR energy rates are determined by adjusting each  
8 PFp Load Shaping rate by an equal scalar until the NR energy rates recover the allocated  
9 NR revenue requirement minus the forecast NR Demand Charge revenue. *Id.*

10  
11 After the scaling process is complete, an REP Surcharge is added to each of the  
12 monthly/diurnal energy rates. Section 7(b)(3) of the Northwest Power Act provides that  
13 the cost of 7(b)(2) rate protection afforded to preference customers is allocated to all other  
14 power sold, which includes power sold at the NR rate. 16 U.S.C. § 839e(b)(2)-(3); *see*  
15 § 2.2.2.4 above. The cost of rate protection allocated to the NR rate is determined pursuant  
16 to the 2012 REP Settlement. Refer to Power Rates Study Documentation, BP-24-FS-  
17 BPA-01A, Table 2.4.14, for the calculation of the REP Surcharge.

18  
19 A customer's billing determinant for the NR Energy charge is the total of the customer's  
20 NR hourly loads for each diurnal period.

21  
22 The NR Energy rates are subject to risk adjustments during the Rate Period pursuant to the  
23 Power CRAC, the Power RDC, and the Power FRP Surcharge. *See* § 5.2 below. Any  
24 adjustments to rates and GRSPs during the Rate Period due to such risk adjustments will be  
25 summarized in Appendix A of the Power Rate Schedules GRSPs. *See* 2024 Power Rate  
26 Schedules and GRSPs, BP-24-A-02-AP01, NR-24, § 2.1.1.2.

1 **4.2.2 NR Demand Charge**

2 The Demand rates for the NR rate schedule are equal to the PFp Demand rates described in  
3 Section 4.1.1.2 above. As with the PFp Demand Charge, the NR Demand Billing  
4 Determinant is only a portion of the peak demand placed on BPA. The NR Demand Billing  
5 Determinant is equal to the highest NR Hourly Load during HLH minus the average hourly  
6 HLH energy purchased in that particular month at the NR energy rates.

7  
8 **4.2.3 Unanticipated Load Service Charge**

9 ULS is available under the NR-24 rate schedule for NLSLs and requirements service  
10 requested by investor-owned utilities. See Section 5.10 below and the 2024 Power Rate  
11 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.M, for details.

12  
13 **4.2.4 NR Services for Non-Federal Resources**

14 NR Services for NLSLs are applicable to Load Following customers serving NLSLs with  
15 non-Federal resources. NR Energy Shaping Service is discussed in Section 5.6.2.1 below  
16 and specified in the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.J.1,  
17 and NRFS is discussed in Section 5.6.2.2 below and specified in the 2024 Power Rate  
18 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.J.2.

19  
20 **4.3 Industrial Firm Power (IP-24) Rate**

21 The IP-24 rate schedule is available for firm power sales to DSIs pursuant to Section 5(d) of  
22 the Northwest Power Act. 16 U.S.C. § 839c(d). The IP-24 rate includes energy and demand  
23 rates. DSIs purchasing power pursuant to the IP-24 rate schedule are required to provide  
24 the Minimum DSI Operating Reserve–Supplemental.

1 **4.3.1 IP Energy Charge**

2 **4.3.1.1 IP Energy Rates**

3 The IP rate design includes 24 monthly/diurnal energy rates, two for each month, and one  
4 each for HLH and LLH. The IP energy rates are shaped using the PFp Melded rates. *See*  
5 § 4.1.3 above.

6  
7 As described below, IP Energy rates are calculated by adjusting the PFp Melded rates by the  
8 VOR Credit for operating reserves provided by the DSI load, the typical industrial margin,  
9 and an REP Surcharge. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A,  
10 Table 3.1.8.3.

11  
12 The IP Energy rates are subject to risk adjustments during the Rate Period pursuant to the  
13 Power CRAC; the Power RDC; and the Power FRP Surcharge. *See* § 5.2 below. Any  
14 adjustments to rates and GRSPs during the Rate Period due to such risk adjustments will be  
15 summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2024 Power Rate  
16 Schedules and GRSPs, BP-24-A-02-AP01, IP-24, § 2.1.1.3.

17  
18 **4.3.1.1.1 IP Adjustment for Value of Reserves Provided**

19 A VOR Credit is included in the IP rate, as provided in Section 7(c)(3) of the Northwest  
20 Power Act. 16 U.S.C. § 839e(c)(3); *see* § 2.2.2.5.2 above. The forecast DSI load amount is  
21 shown in the Power Loads and Resources Study, BP-24-FS-BPA-03, § 2.4. Based on  
22 provisions of DSI contracts currently in place, these power sales are assumed to provide  
23 interruption reserve rights (operating reserves) to BPA, and therefore the IP rate includes  
24 a VOR Credit.

25  
26 The first step for valuing operating reserves provided by DSIs is to determine a marginal  
27 price for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve

1 obligations, the cost of Operating Reserves–Supplemental service is used to establish the  
2 marginal value.

3  
4 The second step in valuing the DSI reserves is to determine the quantity of reserves  
5 provided. To calculate this quantity, the total DSI load is reduced to account for wheel-  
6 turning load that cannot be curtailed. The wheel-turning load is forecast to be 0 average  
7 megawatts (aMW). The interruption reserves provided are 10 percent of the remaining  
8 DSI load (11 MW), or 1.1 MW.

9  
10 The VOR Credit included in the IP-24 rate is 0.809 mills/kWh. See Power Rates Study  
11 Documentation, BP-24-FS-BPA-01A, Table 2.4.1, for calculation of the value of DSI reserves.

#### 12 13 **4.3.1.1.2 IP Rate Typical Margin**

14 Another component of the IP rate is the typical margin, as provided in Section 7(c)(2) of the  
15 Northwest Power Act. 16 U.S.C. § 839e(c)(2); *see* § 2.2.2.5.2 above. The typical margin is  
16 based generally on the overhead costs that COUs add to the cost of power in setting their  
17 retail industrial rates. The typical margin included in the IP-24 rate is 0.910 mills/kWh.  
18 The typical margin is calculated in Appendix A.

#### 19 20 **4.3.1.1.3 REP Surcharge**

21 The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest  
22 Power Act provides that the cost of 7(b)(2) rate protection afforded to preference  
23 customers must be allocated to all other power sold, which includes power sold at the IP  
24 rate. 16 U.S.C. §§ 839e(b)(2)-(3); *see* § 2.2.2.3 above. The cost of rate protection allocated  
25 to the IP rate is determined pursuant to the 2012 REP Settlement and is included in the

1 IP-24 rate. See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.4.14, for  
2 calculation of the REP Surcharge.

#### 3 4 **4.3.1.2 IP Energy Charge Billing Determinant**

5 The customer-specific energy billing determinant is the Energy Entitlement specified in the  
6 customer's contract.

#### 7 8 **4.3.2 IP Demand Charge**

9 The demand rates for the IP rate schedule are equal to the PFp Demand rates described in  
10 Section 4.1.1.2 above. As with the PFp Demand Charge, the IP Demand Billing Determinant  
11 is applied to only a portion of the DSI peak demand placed on BPA. The IP Demand Billing  
12 Determinant in each billing month is equal to a DSI's highest HLH schedule, or metered  
13 amount, minus the average HLH schedule amount, or metered amount, less any applicable  
14 Industrial Demand Adjuster. The Industrial Demand Adjuster is a monthly demand  
15 (expressed in kilowatts) that is subtracted from the hourly peak schedule amount when  
16 calculating the IP Demand Billing Determinant. See 2024 Power Rate Schedules and GRSPs,  
17 BP-24-A-02-AP01, IP-24, § 2.2.2.

#### 18 19 **4.4 Firm Power and Surplus Products and Services (FPS-24) Rate**

20 Products and services available under the FPS rate schedule are listed in the next  
21 paragraph and described in the FPS-24 rate schedule. Sales under this rate schedule are  
22 discretionary; BPA is not obligated to sell any of these products, even if such sales will not  
23 displace PF, NR, or IP sales. Products priced under the FPS-24 rate schedule may be sold at  
24 market-based or negotiated rates, which may have a demand component, an energy  
25 component, or both. Rates and billing determinants for the products and services sold



1 under the FPS rate schedule are either specified by BPA or mutually agreed upon by BPA  
2 and the customer. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, FPS-24.

#### 3 4 **4.4.1 FPS Charges**

5 When available for use within and outside the Pacific Northwest, the FPS-24 rate schedule  
6 has ten categories of products and services:

- 7 1. Firm Power (capacity and/or energy), including secondary energy or firm capacity.
- 8 2. Capacity Without Energy: stand-alone capacity products.
- 9 3. Energy shaping services.
- 10 4. Reservations and rights to change services: reservations of power and services,  
11 when available, and the rights to change sales and services.
- 12 5. Reassignment or remarketing of surplus transmission capacity: Power Services may  
13 reassign or remarket its surplus transmission capacity that has been purchased  
14 from a transmission provider, including BPA's Transmission Services, consistent  
15 with the terms of the transmission provider's Open Access Transmission Tariff.
- 16 6. Other capacity, energy, and power scheduling products and services, as available.
- 17 7. Services for non-Federal resources:
  - 18 a. Transmission Scheduling Service and Transmission Curtailment  
19 Management Service, § 5.6.1.5 below and 2024 Power Rate Schedules and  
20 GRSPs, BP-24-A-02-AP01, GRSP II.I.5.
  - 21 b. Forced Outage Reserve Service, § 5.6.1.4 below and 2024 Power Rate  
22 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.I.4.
  - 23 c. Resource Remarketing Service, § 5.6.1.8 below and 2024 Power Rate  
24 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.I.7.

1 8. Unanticipated Load Service, § 5.10 below and 2024 Power Rate Schedules and  
2 GRSPs, BP-24-A-02-AP01, GRSP II.M.4.

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

5 10. Firm Water Transition Power: Pursuant to the BP-24 Settlement, Power Services  
6 will sell power to specific Slice/Block customers to transition such customers to  
7 BPA's 30 water-year and 10<sup>th</sup> percentile metric for measuring firm output of the  
8 Tier 1 system.

9 *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, FPS-24.  
10

#### 11 **4.4.2 FPS Real Power Losses Service**

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

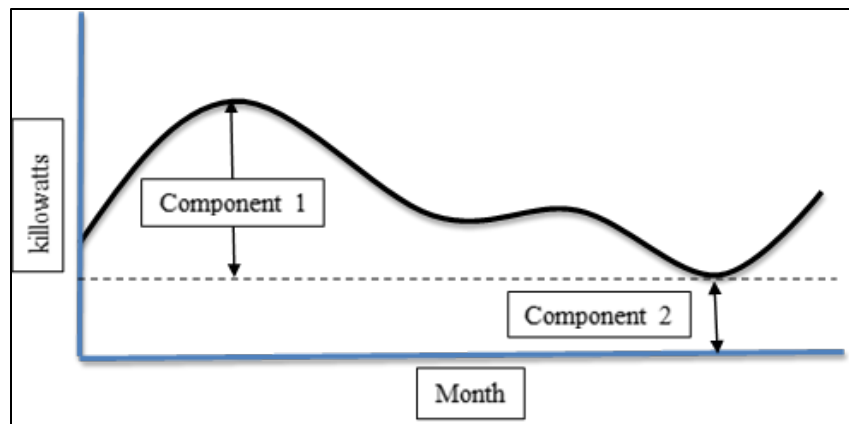
##### 19 **4.4.2.1 Energy Cost of Providing Real Power Losses**

20 The energy cost of providing real power losses will be based on actual hourly market prices  
21 from the hour the loss obligation occurred. The market prices will be the greater of 0 and  
22 the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market  
23 Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss  
24 occurred. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to  
25 the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.  
26

#### 4.4.2.2 Capacity Cost of Providing Real Power Losses

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

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



1 **Capacity Cost Component 1:**

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

14

$$15 \quad AveMaxMonth_i = \sum_{i=1}^{12} \frac{[HrMaxMonth_{i_{2019}} + HrMaxMonth_{i_{2020}} + HrMaxMonth_{i_{2021}}]}{3}$$

16

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

17

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

18

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

19 *Where:*

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

22  $HrMaxMonth_{i_{2019}}$  refers to the maximum hourly value in month *i* of fiscal year  
23 2019.

1  $HrMaxMonth_{i_{2020}}$  refers to the maximum hourly value in month  $i$  of fiscal year  
2 2020.

3  $HrMaxMonth_{i_{2021}}$  refers to the maximum hourly value in month  $i$  of fiscal year  
4 2021.

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

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

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

8  $UC_{Sup}$  refers to the unit cost for Supplemental Operating reserves.

9  $CapacityCostComp_1$  refers to the total annual cost of capacity cost component one.

10  
11 **Capacity Cost Component 2:**

12 Capacity cost component 2 is calculated in two steps. Step one is to multiply the average  
13 minimum amount of power provided for each month of the year (*i.e.*, for the month of  
14 March, the calculation would be the average of the minimum hourly March 2019, minimum  
15 hourly March 2020, and minimum hourly March 2021) by the average amount of hours for  
16 that same month (*i.e.*, for the month of March, the calculation would be the average of the  
17 hours in March 2019, the hours in March 2020, and the hours in March 2021). Step two is  
18 to multiply the total amount of kilowatthours calculated in step one by 1 mill/kWh.

19  
20 
$$AveMinMonth_i = \sum_{i=1}^{12} \frac{[HrMinMonth_{i_{2019}} + HrMinMonth_{i_{2020}} + HrMinMonth_{i_{2021}}]}{3}$$

21 
$$AveHrsMonth_i = \sum_{i=1}^{12} \frac{[HrsMonth_{i_{2019}} + HrsMonth_{i_{2020}} + HrsMonth_{i_{2021}}]}{3}$$

22 
$$AveAnnualPower = AveMinMonth_i \times AveHrsMonth_i$$

23 
$$CapacityCostComp_2 = AveAnnualPower \times 1 \text{ mill per kWh}$$

1 *Where:*

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

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

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

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

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

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

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

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

11  
12 Capacity cost component one and two are summed and divide by the average annual  
13 amount of kilowatt-hours from the same historical dataset to compute a volumetric dollars  
14 per kilowatthour capacity charge applied in addition to the energy charge for real power  
15 losses purchases from BPA. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A,  
16 Table 4.4.

#### 18 **4.4.3 Firm Water Transition Power**

19 In June 2022, BPA decided to to update its base assumptions for long-term hydropower  
20 generation planning to capture observed and emerging climate change trends in the  
21 Columbia River Basin. Going forward, BPA will use the recent 30-year subset of  
22 streamflows as opposed to the historical record going back to 1929. BPA will also use a  
23 monthly 10th percentile from the generation output of hydro regulation studies to  
24 establish firm generation, rather than using the generation from the 1937 water year,  
25 which had the lowest winter runoff on record. *See* Power Loads and Resources Study,  
26 BP-24-FS-BPA-03, § 3.1.2.

1 This updated metric for establishing firm water results in higher Critical Slice Amounts and  
2 lower Tier 1 Block amounts for some Slice/Block customers. In FY 2024 and FY 2025,  
3 consistent with the BP-24 Rates settlement, BPA is selling firm surplus power to specific  
4 Slice/Block customers to transition such customers to the 30-water-year and 10<sup>th</sup>  
5 percentile metric for measuring output of the Tier 1 system. This power will be sold at the  
6 FPS Firm Water Transition Power energy rates, which are equal to the PF Tier 1 Equivalent  
7 energy rates described in Section 5.14 below. Customers purchasing this power, and the  
8 amounts of power the customers will purchase, are listed in Section 10 of the FPS-24 rate  
9 schedule of the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, FPS-24, § 10.

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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 2024 Power Rate Schedules and GRSPs, BP-24-A-02-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, Section 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 2024-2025 rate period are shown in the 2024  
19 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.A, Table A.

20  
21 **5.2 Risk Adjustments**

22 Consistent with the BP-24 Rates Settlement, Power risk adjustment clauses will not  
23 be applicable to the portion of a customer’s service at PF Tier 1 rates that has been  
24 converted from a Slice product to a non-Slice product beginning October 1, 2023.  
25 Fredrickson *et al.*, BP-24-FS-BPA-09, Appendix A, Attachment 3, § II.A.11. However,

1 the three risk adjustment clauses will apply to such customer's entire service at PF  
2 Tier 1 rates for FY 2025.

### 4 **5.2.1 Power Cost Recovery Adjustment Clause (Power CRAC)**

5 For each year of the rate period, the Power CRAC may result in an upward rate adjustment  
6 to respond to the financial circumstances BPA experiences before BPA can conduct a  
7 Section 7(i) rate proceeding to adjust its rates. If stated conditions are met, the CRAC will  
8 trigger, and a rate increase will go into effect for the period of December 1 through  
9 September 30 of the applicable year. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-  
10 02-AP01, GRSP II.O; Power and Transmission Risk Study, BP-24-FS-BPA-05, § 4.2.

### 12 **5.2.2 Power Reserves Distribution Clause (Power RDC)**

13 For each year of the rate period, the Power RDC may result in a reduction in Power's  
14 reserves as financial reserves are used to further Power's objectives such as debt  
15 reduction, incremental capital investment, rate reduction through a Power Dividend  
16 Distribution (Power DD), a distribution to customers, or any other Power-specific purposes  
17 determined by the Administrator. The RDC will trigger if (1) financial reserves attributed  
18 to Power exceed a defined threshold, and (2) BPA's financial reserves exceed a defined  
19 threshold. If the RDC triggers, the Administrator will determine what part of the RDC  
20 Amount will be devoted to the Power objectives noted above. If reserves are allocated to a  
21 Power DD, the resulting rate decrease will go into effect for the period of December 1  
22 through September 30 of the applicable year. Consistent with the BP-24 Rates Settlement,  
23 any FY 2024 or 2025 Power RDC will automatically provide a dividend distribution in an  
24 amount equal to the lesser of the RDC amount and the amount of Planned Net Revenues for  
25 Risk included in the BP-24 power rates, which is \$129 million each year. Also, consistent  
26 with the rates settlement, the cap on the Power RDC is removed for the BP-24 rate period,

1 FY 2024-2025. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.P;  
2 Power and Transmission Risk Study, BP-24-FS-BPA-05, § 4.2.

### 4 **5.2.3 Power FRP Surcharge**

5 For each year of the rate period, the Power FRP Surcharge may result in an upward  
6 adjustment to certain rates to increase financial reserves when reserves are below the  
7 lower threshold for Power. *See* Power and Transmission Risk Study, BP-24-FS-BPA-05,  
8 § 4.2. If stated conditions are met, the Power FRP Surcharge will trigger, and a rate  
9 increase will go into effect for the period of December 1 through September 30 of the  
10 applicable year. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.Q.

11  
12 For FY 2024 and FY 2025, Power’s FRP Surcharge amount will be the lesser of \$40 million  
13 per year or the amount needed to fully recover financial reserves up to the lower financial  
14 reserves threshold for Power. *See* Power and Transmission Risk Study, BP-24-FS-BPA-05,  
15 Appendix A (FRP), § 4.2.2.

### 17 **5.3 Slice True-Up Adjustment**

18 Slice customers pay their share of BPA’s actual costs. Therefore, Slice customers are  
19 subject to an annual Slice True-Up Adjustment for expenses, revenue credits, and  
20 adjustments allocated to the Composite cost pool and to the Slice cost pool. *See* § 7;  
21 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.R.

### 23 **5.4 Discounts and Other Adjustments**

#### 24 **5.4.1 Low Density Discount (LDD)**

25 Pursuant to Section 7(d)(1) of the Northwest Power Act, the LDD is a rate discount for  
26 customers with low system densities that meet the criteria specified in the 2024 Power

1 Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.B. 16 U.S.C. § 839e(d)(1). As set  
2 forth in the TRM, LDD percentages are calculated to provide a discount on power  
3 purchased at Tier 1 rates that approximates the discount the customer would have  
4 received under non-tiered rates. LDD credits for FY 2024 and FY 2025 are listed below in  
5 Table 4, Line 9.

#### 6 7 **5.4.2 Irrigation Rate Discount (IRD)**

8 The IRD is a discount to the PFp Tier 1 rates for eligible irrigation load served by  
9 customers. An irrigation credit is available to customers with eligible irrigation load as set  
10 forth in Exhibit D of the customers' CHWM contracts. The amount of irrigation credit a  
11 customer will receive on its monthly bills during the irrigation season is based on the lesser  
12 of the customer's actual Tier 1 energy purchase and the eligible irrigation load amounts in  
13 the customer's CHWM contract. The discount will appear as a credit on customers' bills to  
14 offset Tier 1 charges for eligible irrigation loads. This discount is available to eligible loads  
15 during May, June, July, August, and September during the BP-24 rate period. *See* 2024  
16 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.C. IRD Credits for FY 2024  
17 and FY 2025 are shown in Table 4, Line 8.

#### 18 19 **5.4.2.1 Irrigation Rate Discount True-Up and Reimbursement**

20 At the end of each irrigation season, each customer with eligible irrigation load will provide  
21 to BPA its measured May-through-September irrigation load amounts, which will be used  
22 to determine if a true-up and reimbursement to BPA is applicable. If BPA determines that  
23 the measured irrigation load amounts are less than the billed irrigation load amounts, then  
24 the purchaser must reimburse BPA for the excess IRD Credits. Excess IRD Credits are  
25 calculated as the IRD rate multiplied by the difference between the billed irrigation load

1 and the measured irrigation load. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-  
2 AP01, GRSP II.C.3.

#### 3 4 **5.4.2.2 Calculation of the Irrigation Rate Discount**

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

8  
9 The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads  
10 will pay through the Composite customer charge, Non-Slice customer charge, and Load  
11 Shaping charge, adjusted for any applicable Low Density Discount, divided by the sum of  
12 the irrigation loads (expressed in megawatthours) to derive a dollars-per-megawatthour  
13 discount. The applicable LDD is calculated as the weighted average LDD of eligible  
14 irrigation customers, weighted with eligible irrigation loads. *See* Power Rates Study  
15 Documentation, BP-24-FS-BPA-01A, Table 5.1 for the calculation of the applicable LDD.

16  
17 Forecast revenue for irrigation loads is calculated using an IRD TOCA derived by dividing  
18 the sum of the irrigation loads (expressed in average megawatts) by the sum of all RHWMs.  
19 The IRD TOCA is applied consistent with TRM Section 5 for calculation of forecast irrigation  
20 revenues from the Composite customer charge, Non-Slice customer charge, and Load  
21 Shaping charge. The calculation is shown in Power Rates Study Documentation, BP-24-FS-  
22 BPA-01A, Table 2.3.3.1.

1 **5.4.3 Demand Rate Billing Determinant Adjustment**

2 As described in GRSP II.D, in two limited circumstances BPA may reduce an unusually high  
3 Demand Charge Billing Determinant and provide some demand billing relief to a customer.

4 *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.D.*

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

13  
14 Second, when an Uncontrollable Force outage occurs on a customer’s system, the  
15 restoration of service may result in a spike in usage, called a recovery peak. BPA may  
16 reduce the customer’s system peak established by a recovery peak to the next highest peak  
17 of the month and thereby reduce that month’s billing determinant.

18  
19 **5.4.4 Load Shaping Charge True-Up Adjustment**

20 As noted in TRM Section 5.2.4, at the end of each fiscal year BPA will calculate the Load  
21 Shaping Charge True-Up for each Load Following customer. The purpose of the true-up is  
22 to avoid charging or crediting the market-based Load Shaping rate for energy within the  
23 customer’s RHWM rather than charging or crediting the cost-based Tier 1 rate for that  
24 energy. BPA applies the true-up when a Load Following customer’s TOCA Load or Actual  
25 Annual Tier 1 Load is less than its RHWM. The LSTUR is the difference between (1) the  
26 Non-Slice load-weighted average of the Load Shaping rates, and (2) the Composite  
27 Customer rate plus the Non-Slice Customer rate, converted to mills per kilowatthour.

1 The process for calculating the Load Shaping True-Up Adjustment is shown in TRM, BP-12-  
2 A-03, Section 5.2.4, Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 3.1.8.5,  
3 and the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.E.

#### 5 **5.4.5 Special Implementation Provision for Load Shaping True-Up**

6 The Load Shaping True-Up Adjustment includes a special implementation provision that  
7 applies if two conditions are met: (1) a customer has Above-RHWM Load, and (2) the  
8 customer has unused RHWM. If these conditions are met, the customer may be eligible for  
9 a Load Shaping True-Up Credit in addition to the one described above. The amount of the  
10 additional Load Shaping True-Up Credit depends on a second calculation. *See* 2024 Power  
11 Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.E.3.

12  
13 The special implementation provision was originally designed to solve a transitional  
14 implementation issue caused by setting Above-RHWM Load based on a forecast different  
15 from the one used to determine a customer's TOCA. This provision also has a longer-term  
16 application, because Above-RHWM Load is determined in the RHWM Process (prior to the  
17 Initial Proposal of each rate proceeding). A Load Following customer's TOCA can be  
18 updated prior to each fiscal year, or within a fiscal year, if there is substantial reason for  
19 BPA to believe the customer's Actual Annual Tier 1 Load will be different than the forecast  
20 Tier 1 Load determined in the RHWM Process or the applicable year. *See* 2024 Power Rate  
21 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.G.1. A consequence of using forecasts  
22 prepared at different times is the possibility that a customer could have both Above-RHWM  
23 Load and unused RHWM.

1 **5.4.6 Tier 2 Rate Transmission Curtailment Management Service Adjustment**

2 The Tier 2 rate schedule includes an adjustment for TCMS-related costs. This adjustment  
3 will recover the cost BPA incurs as a result of a transmission event – either a planned  
4 transmission outage or a transmission curtailment. The event would occur along the  
5 transmission path used to deliver energy associated with power purchases for the Tier 2  
6 cost pools; that is, it would occur between the Point of Receipt and the Point of Delivery.  
7 The adjustment is described in the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-  
8 AP01, GRSP II.F.

9  
10 **5.4.7 TOCA Adjustment**

11 For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA  
12 for each year of the rate period is calculated in the BP-24 7(i) process. A Load Following  
13 customer’s TOCA for a fiscal year may be adjusted (1) to account for a significant change in  
14 the customer’s total load, and (2) within a fiscal year due to a change to the customer’s  
15 Existing Resource amounts within the same fiscal year, as detailed in the 2024 Power Rate  
16 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.G.1. A Slice/Block or Block customer’s  
17 TOCA may be adjusted (1) for a fiscal year as part of the CHWM contract annual Net  
18 Requirement process, and (2) within a fiscal year due to a change to the customer’s  
19 Specified Resource amounts within the same fiscal year, as detailed in the 2024 Power Rate  
20 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.G.2. Additionally, a customer’s TOCA may  
21 be modified for a fiscal year or within a fiscal year if the customer’s CHWM and associated  
22 RHWM have changed due to load annexations between customers with CHWM contracts.

23  
24 **5.4.8 DSI Reserves Adjustment**

25 In the event BPA agrees to acquire an additional reserve product from a DSI, this provision  
26 (1) establishes the mechanism through which BPA compensates the DSI, and (2) places a



1 cap on the unit price of any supplemental operating reserve product to be purchased to  
2 ensure that the reserve acquisition is cost-effective. *See* 2024 Power Rate Schedules and  
3 GRSPs, BP-24-A-02-AP01, GRSP II.H.

#### 4 5 **5.5 Conservation Surcharge**

6 Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge  
7 recommended by the NPCC pursuant to Section 4(f)(2) of the Act. 16 U.S.C. §§ 839e(h),  
8 839b(f)(2). BPA does not currently anticipate applying such a surcharge in the FY 2024-  
9 2025 rate period. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.U.

#### 10 11 **5.6 Resource Support Services and Related Services**

12 BPA offers services to support resources under the PF, NR, and FPS rate schedules. These  
13 services are designed to support non-Federal resources; however, there are situations for  
14 ratemaking purposes where these services are used to financially flatten Federal resources.  
15 *See* § 3.2.3.1.3 above. The RSS rates relevant to the PFp rate schedule include:

- 16 • Diurnal Flattening Service Charges
- 17 • Resource Shaping Charge and Resource Shaping Charge Adjustment
- 18 • Secondary Crediting Service Charges
- 19 • Grandfathered Generation Management Service Reservation Fee

20  
21 The RSS and related service rates relevant to the NR rate schedule for NLSLs include:

- 22 • NR Energy Shaping Service Charges
- 23 • NR Resource Flattening Service Charge

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

- 2 • Forced Outage Reserve Service Charges
- 3 • Transmission Scheduling Service Charges
- 4 • Transmission Curtailment Management Service Charges
- 5 • Resource Remarketing Service Credits

6  
7 Forecast revenue from RSS and related services is used to credit Tier 1 cost pools. *See*  
8 *Power Rates Study Documentation, BP-24-FS-BPA-01A, Tables 3.2 and 3.7.*

## 9 10 **5.6.1 Resource Support Services and Transmission Scheduling Service**

### 11 **5.6.1.1 Diurnal Flattening Service**

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

18  
19 The RSS module of RAM2024 calculates a unique set of rates and charges for each resource  
20 to which DFS is applied. Included in *Power Rates Study Documentation, BP-24-FS-*  
21 *BPA-01A, Table 3.11* are the final rates and charges calculated for customers that have  
22 requested DFS for their resources. PF-24 rate schedule Sections 5.1 and 5.2 describe the  
23 general rate application of the DFS-related charges. GRSP II.I includes DFS rates and RSC.  
24 *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.*

1 DFS charges include the following elements:

- 2 • A DFS capacity charge based on the PFp Tier 1 Demand rate applied to the  
3 difference between the calculated firm capacity of the resource and the planned  
4 average HLH generation of the resource. This charge reflects the costs of reserving  
5 an amount of capacity to smooth the variable generation of a resource into a flat  
6 block of power.
- 7 • A DFS energy charge based on the potential cost of storing and releasing power  
8 using a resource capable of storing energy (pumped storage) to balance the hourly  
9 shape of the resource to which DFS is applied. This charge reflects the costs of  
10 energy storage to smooth the hourly generation variation into a flat  
11 monthly/diurnal block of power.

12  
13 When DFS is applied to a resource, the RSC and Adjustment must be added to the DFS  
14 charges to complete the financial conversion to a flat annual block of power. *See*  
15 §§ 5.6.1.2-3 below.

16  
17 Typically, the RSS module of RAM2024, which computes resource-specific RSS rates, will  
18 use scheduled amounts for resources that require e-Tags and meter amounts for “behind-  
19 the-meter” resources. However, for small resources or small shares of a resource, BPA may  
20 apply a meter amount instead of a schedule amount for purposes of pricing RSS if the meter  
21 amount produces lower RSS rates and charges.

#### 22 23 **5.6.1.1.1 DFS Energy Charge**

24 A unique DFS energy rate is developed for each resource to which DFS is applied. The  
25 purpose of this rate is to reflect the potential cost of storing and releasing energy to offset  
26 the hourly variability of the resource’s Exhibit D amounts. The DFS Energy Billing

1 Determinant is the total actual generation. The DFS energy charge, GRSP II.I.1(a), is the  
2 product of multiplying the DFS energy rate by the DFS Energy Billing Determinant for each  
3 month. *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs. Power Rates*  
4 *Study Documentation, BP-24-FS-BPA-01A, Table 3.11 shows the DFS energy rates for the*  
5 *individual resources.*

#### 6 7 **5.6.1.1.2 DFS Capacity Charge**

8 The DFS capacity charge is a fixed monthly amount calculated as noted in GRSP II.I.1(b)(3)  
9 and is based on the monthly PF Tier 1 demand rates, monthly planned amounts in  
10 Exhibit D, and the calculated monthly firm capacity of the resource. *See 2024 Power Rate*  
11 *Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.*

12  
13 The RSS module of RAM2024 calculates the monthly firm capacity amounts for each  
14 resource. This calculation represents the lowest level of historical generation in an HLH  
15 period for each month after accounting for planned and forced outages. The firm capacity  
16 of a resource is the percentile of the forced outage rating calculated from the historical  
17 monthly HLH generation levels. For example, a resource with a 5 percent forced outage  
18 rating would have a firm capacity amount equal to the 5<sup>th</sup> percentile of the hourly historical  
19 generation amounts for the HLH period of a month.

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

1 resource, and those with a resource other than a hydroelectric resource may request that  
2 BPA decrease the forced outage rating to as low as 7 percent.

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

17  
18 Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 3.11 shows the individual  
19 DFS capacity charges that are calculated for the individual resources to which DFS is  
20 applied.

### 21 22 **5.6.1.2 Resource Shaping Charge**

23 The purpose of the RSC, GRSP II.I.2(a), is to reflect the value of buying and selling flat  
24 monthly/diurnal blocks of power in the market to convert a diurnally flat resource within  
25 the month into one that, on a planned basis, is flat across the year. *See 2024 Power Rate*  
26 *Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.* The Resource Shaping rates are set equal

1 to the PFp Tier 1 Load Shaping rates, which represent a proxy market price. On a monthly  
2 basis the RSC can be a charge or a credit. The flat monthly RSCs are shown in Power Rates  
3 Study Documentation, BP-24-FS-BPA-01A, Table 3.11 for individual resources.

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

#### 9 10 **5.6.1.3 Resource Shaping Charge Adjustment**

11 The purpose of the RSC Adjustment, GRSP II.I.2(b), is to capture the cost or value of the  
12 energy differences between the Exhibit D amounts and the actual generation of the  
13 resource. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs. This  
14 adjustment is a true-up of the RSC and completes the financial conversion to a flat annual  
15 block of power by making up for any energy cost differences between planned and actual  
16 generation amounts. The RSC Adjustment can result in either a charge or a credit.

#### 17 18 **5.6.1.4 Forced Outage Reserve Service (FORS)**

19 FORS in GRSP II.I.4 is an optional service for BPA to provide an agreed-upon amount of  
20 capacity and energy to a customer with a qualifying resource that experiences a forced  
21 outage. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs. FORS is  
22 offered under the FPS rate schedule to customers with resources that meet requirements  
23 specified in the CHWM contract.

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

4  
5 The FORS charges include the following elements:

- 6 • A FORS Capacity charge based on the PFp Tier 1 Demand rate, the calculated firm  
7 capacity of the resource for customers whose resource is also taking DFS, and the  
8 forced outage rating for the applicable resource. Power Rates Study Documentation,  
9 BP-24-FS-BPA-01A, Table 3.11 shows the FORS Capacity charges calculated for each  
10 resource. The calculations regarding firm capacity and forced outage ratings are  
11 described above in Section 5.6.1.1.2. Additionally, the firm capacity amounts used to  
12 calculate the FORS Capacity charges may be adjusted to account for planned outages  
13 if such planned outages are included in the DFS Capacity charge.
- 14 • A FORS Energy charge designed to pass through the cost of replacement energy that  
15 BPA provides during a customer's forced outage. The energy rate is based on a  
16 market price under two conditions and the amount of energy supplied during a  
17 forced outage event.

18  
19 Additionally, customers with FORS are limited to a maximum amount of energy provided  
20 during a fiscal year and a purchase period, as defined in the CHWM contracts. Such fiscal  
21 year and purchase period limits are calculated in the RSS module of RAM2024 and listed in  
22 Exhibit D of the customer's CHWM contract. The fiscal year limits are set equal to two  
23 times the product of the following: (1) the forced outage rating of the applicable resource,  
24 and (2) the sum of the monthly planned amounts in Exhibit D in megawatthours. The  
25 purchase period limits are set equal to the product of the following: (1) the forced outage

1 rating of the applicable resource; (2) the annual average planned amounts in Exhibit D in  
2 megawatthours; and (3) the number of years in the purchase period.

3  
4 **5.6.1.5 Transmission Scheduling Service (TSS) and Transmission Curtailment**  
5 **Management Service (TCMS)**

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

19  
20 If a Load Following customer is served by transfer service or is purchasing DFS or SCS  
21 services from BPA, it is required to have the TSS provisions added to its CHWM contract.  
22 However, only customers that have non-Federal resources requiring e-Tags will be charged  
23 for TSS services. Customers that have one or multiple non-Federal resource(s) requiring  
24 e-Tags may choose either TSS-Full or TSS-Partial for all of their non-Federal resources that  
25 require e-Tags. Load Following customers that are not contractually required to take TSS  
26 can elect this optional service if they wish to have BPA produce the e-Tags for their



1 resources. Without this service, the customer must supply replacement transmission or  
2 power when the resource's transmission path experiences an outage or curtailment. If it is  
3 unable to do so, it may face an Unauthorized Increase charge. *See 2024 Power Rate*  
4 *Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.N.*

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

#### 8 9 **5.6.1.5.1 TSS-Full Pricing Summary**

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

- 13 • For resources requiring e-Tags, a monthly TSS charge based on the applicable  
14 resource's FY 2024-2025 Dedicated Resource amounts listed in Exhibit A of the  
15 Load Following CHWM contract.
- 16 • A TSS-Full rate that is based on the forecast operations scheduling cost for the rate  
17 period (including costs associated with power scheduling preschedule, real-time,  
18 and after-the-fact functions) divided by the total megawatthours of power BPA  
19 scheduled in FY 2020 and FY 2021. *See Power Rates Study Documentation, BP-24-*  
20 *FS-BPA-01A, Table 3.4.*
- 21 • An Annual Open Access Technology International, Inc. (OATI) registration fee,  
22 \$200 per customer, which is spread evenly across the customer's resources and  
23 billing periods.
- 24 • A transaction-based cap for the monthly TSS-Full charge (not including adjustments  
25 made to recover the cost of the OATI registration fee). *See Section 5.6.1.5.2 below*  
26 *for details.*

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The RSS module of RAM2024 calculates a TSS-Full rate that is applied to each non-Federal resource receiving service during the rate period. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 3.11.

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

The TSS-Full Charge, not including adjustments made to recover the cost of the OATI registration fee described above, is subject to a cap. For a Specified Resource or Unspecified Resource Amounts serving Above-RHWM Load, if the annual cost calculated using the TSS rate exceeds \$1,005 when divided by 12, then the monthly charge is capped at \$1,005/month. The cap is the result of multiplying 30 schedules per month (*e.g.*, one schedule per day on average) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2020 and FY 2021. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP III.5(a)(3).

For Unspecified Resource Amounts serving an NLSL or a 9(c) export decrement obligation, if the annual cost calculated using the TSS rate exceeds \$3,014 when divided by 12, then the monthly charge is capped at \$3,014/month. This cap follows the same methodology applied to Specified Resources and Unspecified Resource Amounts serving Above-RHWM Load but assumes three daily transactions. It is the result of multiplying 90 schedules per month (*e.g.*, three schedules per day on average) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2020 and FY 2021. *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 \$244 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 \$169,000 (including benefits) per year, or \$81.25 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 (BPA Power) was included in the  
16 market path on the tag; or (2) a day that a customer has a TCMS charge.

17 *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-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 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

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

The PF-24 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 2024 Power Rate Schedules and GRSPs, BP-24-A-02-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 Grandfathered Generation Management Service.

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-24-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* 2024 Power Rate  
3 Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

#### 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 2024 Power Rate Schedules and GRSPs, BP-24-A-01-AP01, GRSPs.

#### 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 § 5.7.2.4  
18 below.

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

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

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

1 applies to the amount of capacity that a customer requests BPA to stand ready to provide to  
2 the customer's NLSL(s).

3  
4 The ESS Charges in GRSP II.J.1 include the following elements:

- 5 • The energy component credits or debits the customer for energy differences  
6 between the energy amounts provided by the customer's non-Federal resource  
7 serving its NLSL(s) and the customer's measured NLSL(s).
- 8 • Energy charges can be positive or negative and are determined in a two-step  
9 process.
- 10 • The NR ESS Capacity Charge is based on the NR demand rate and the amount of  
11 capacity the customer requests from BPA for standing ready to serve its NLSL(s).

12 *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.*

13 NR energy rates will apply to any net monthly energy amounts purchased from BPA. The  
14 Unauthorized Increase Charge for demand will apply to actual capacity amounts used in  
15 excess of the monthly amounts of capacity included in the customer's request to BPA.

#### 16 17 **5.6.2.2 NR Resource Flattening Service**

18 The NRFS is applicable to Load Following customers that apply the generation output of a  
19 non-dispatchable Specified Resource to a NLSL. This service financially converts, excluding  
20 the cost of capacity, the output of a non-dispatchable Specified Resource to the equivalent  
21 flat amount of power within each diurnal period of the month. *See 2024 Power Rate*  
22 *Schedules and GRSPs, BP-24-A-02-AP01, NR-24 and GRSP II.J.2.* The capacity costs of  
23 diurnally flattening the resources are excluded from NRFS because this service is offered in  
24 conjunction with the ESS service, and the capacity costs are included in that service.

1 The NRFS Charges, GRSP II.J.2, include an NRFS energy charge based on the potential cost  
2 of storing and releasing power using a resource capable of storing energy (*e.g.*, pumped  
3 storage) to balance the hourly shape of the resource. *See 2024 Power Rate Schedules and*  
4 *GRSPs, BP-24-A-02-AP01, GRSPs.* This charge reflects the costs of energy storage to  
5 smooth the hourly generation variation into a flat monthly/diurnal block of power.  
6

7 No customers are forecast to take NRFS during the BP-24 rate period. GRSP II.J.2 includes  
8 the calculation for NRFS Energy Charges for the individual resources if the NRFS is  
9 required. *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.*  
10

## 11 **5.7 Resource Remarketing for Individual Customers**

12 The Remarketing Credit conveys the value BPA receives when it remarkets (1) committed  
13 Tier 2 purchases in excess of need, and (2) non-Federal resources to which DFS applies that  
14 are temporarily in excess of need. The excess power is created when commitments to  
15 purchase are made prior to establishing need in the RHWM Process. *See 2024 Power Rate*  
16 *Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.K.*  
17

### 18 **5.7.1 Tier 2 Remarketing**

#### 19 **5.7.1.1 Tier 2 Remarketing for Load Following Customers**

20 Section 10 of the CHWM contract states that a Load Following customer may elect to have  
21 BPA remarket its Tier 2 rate purchase amount in the event its Above-RHWM Load as  
22 forecast for an upcoming rate period year is less than the sum of its Tier 2 rate purchase  
23 amounts and new resource amounts. The Load Following customer must provide BPA  
24 notice of such election by October 31 of the year preceding the rate period for which the  
25 customer elects to have BPA remarket its Tier 2 purchase amount.  
26

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 RHW 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  
17 (2) the Remarketing Value determined in accordance with Section 3.2.2.6 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 2024 and FY 2025.

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

21  
22 For each resource, the DFS Remarketing Credit will be the product of multiplying the DFS  
23 remarketing rate by the DFS Remarketing Billing Determinant for each applicable year of  
24 the rate period. The annual value is divided by 12 to calculate a flat monthly credit. Power  
25 Rates Study Documentation, BP-24-FS-BPA-01A, Table 5.2 shows the forecast monthly DFS  
26 Remarketing Credits that are calculated for the individual resources to which the DFS

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

#### 5 **5.7.2.4 Resource Remarketing Service**

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

##### 15 **5.7.2.4.1 RRS Credits**

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

- 17 • RRS Rate. For each non-Federal resource, the rate will be based on the Remarketing  
18 Value determined in accordance with Section 3.2.2.6.
- 19 • RRS Billing Determinant. The RRS Billing Determinant will be the annual average  
20 megawatt Resource Remarketed Amounts in the customer's CHWM contract  
21 Exhibit D (when updated).
- 22 • RRS Credit. For each resource, the RRS Credit will be the product of multiplying the  
23 RRS rate by the RRS Billing Determinant for each applicable year of the rate period.  
24 The annual value is divided by 12 to calculate a flat monthly credit.
- 25 • RRS Fee. The fee for providing RRS to customers is determined on a case-by-case  
26 basis.

1 See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

## 3 **5.8 Transfer Service**

4 About half of BPA's power customers are served by the transmission systems of third  
5 parties (entities other than BPA). Under the CHWM contract, BPA must acquire  
6 transmission services from these third-party transmission providers to deliver Federal  
7 power to BPA's power customers. This third-party transmission service is commonly  
8 referred to as transfer service. For information about transfer service, see Section 6 below  
9 and the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.L.

## 11 **5.9 Rate Payment Options**

### 12 **5.9.1 Flexible PF Rate Option**

13 The Flexible PF rate option, offered at BPA's discretion, allows PF-24 rates and billing  
14 determinants to be modified to accommodate a customer's request to change the way  
15 power is charged under the PF-24 rate schedule. See 2024 Power Rate Schedules and  
16 GRSPs, BP-24-A-02-AP01, GRSP II.W.

### 18 **5.9.2 Priority Firm Power Shaping Option**

19 If requested, BPA will, to the maximum extent practicable while ensuring timely BPA cost  
20 recovery, accommodate individual customer requests to reshape charges within each year  
21 of the rate period to mitigate adverse cash flow effects on the customer. Such reshaping of  
22 charges must recover the same number of dollars on a net present value basis within the  
23 fiscal year as would have been recovered without the reshaping. The reshaping of the  
24 payments will be agreed upon between BPA and the customer prior to the start of the rate  
25 period. See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.X.

1 **5.9.3 Flexible NR Rate Option**

2 The Flexible NR rate option, offered at BPA’s discretion, allows NR-24 rates and billing  
3 determinants to be modified to accommodate a customer’s request to change the way  
4 power is charged under the NR-24 rate schedule. *See* 2024 Power Rate Schedules and  
5 GRSPs, BP-24-A-02-AP01, GRSP II.Y.

6  
7 **5.10 Unanticipated Load Service**

8 ULS applies to any request for Firm Requirements Power received after February 1, 2023,  
9 that results in an unanticipated increase in a customer’s load placed on BPA during the  
10 FY 2024-2025 rate period. Contractual obligations that result from a request for service  
11 under Section 9(i) of the Northwest Power Act also will be considered ULS. 16 U.S.C.  
12 § 839f(i). ULS may also apply to a customer that adds load through retail access, including  
13 load that was once served by the customer and returns under retail access. *See* 2024  
14 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.M.

15  
16 **5.10.1 PF Unanticipated Load Service**

17 The energy rate is equal to the greater of the following: (1) the rate for the applicable  
18 diurnal period in GRSP II.M.2; or (2) the projected market price for the applicable diurnal  
19 period calculated after a request for ULS is made. The energy rates in GRSP II.M.2 are equal  
20 to the PF Tier 1 Equivalent rates and were determined by taking the greater of (1) the Load  
21 Shaping rates, or (2) the PF Tier 1 Equivalent rates. *See* Section 4.1.1.3.1 above for a  
22 description of the Load Shaping rates and Section 5.14 below for a description of the  
23 PF Tier 1 Equivalent rates. The PF ULS also includes a Demand Charge, which uses the  
24 PF-24 Demand Rate. The ULS under the PF-24 Rate Schedule is specified in GRSP II.M.2.  
25 *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

1 **5.10.2 NR Unanticipated Load Service**

2 The energy rate is equal to the greater of (1) the rate for the applicable diurnal period in  
3 GRSP II.M.3; or (2) the projected market price for the applicable diurnal period calculated  
4 after a request for ULS is made. The energy rates in GRSP II.M.3 are equal to the NR energy  
5 rates and were determined by taking the greater of (1) the Load Shaping rates, or (2) the  
6 NR Energy rates. See Section 4.1.1.3.1 above for a description of the Load Shaping rates  
7 and Section 4.2.1 above for a description of the NR energy rates. The NR ULS also includes  
8 a Demand Charge, which uses the NR-24 Demand Rate. The ULS under the NR-24 Rate  
9 Schedule is specified in GRSP II.M.3. *See 2024 Power Rate Schedules and GRSPs, 2, GRSPs.*

10  
11 **5.10.3 FPS Unanticipated Load Service**

12 Under the FPS-24 rate schedule, the Resource Replacement (RR) rate or a projected market  
13 price will be applied to ULS for circumstances that cause an increase in a customer's load  
14 placed on BPA not anticipated in the rate case. Such circumstances could include, but are  
15 not limited to, delays in the online date of a customer's specified resource for  
16 Above-RHWM service; New Specified Resources that are 10 aMW or less and either  
17 experience permanent failure during the rate period or fail to come online; and transfer  
18 service customers that both (1) cannot secure Firm Network Transmission (NT) from  
19 source to sink for their dedicated non-Federal resource to their Above-RHWM Load by the  
20 time power deliveries begin under the Regional Dialogue contract, and (2) are expected to  
21 face high TCMS Charges due to their reliance on Secondary Network Transmission while  
22 they pursue Firm Network Transmission. The provision of ULS will be at BPA's sole  
23 discretion.

24  
25 The energy rate is the greater of (1) the RR rate, and (2) the projected market price  
26 calculated after the time when the request for ULS is made. The RR rates are equal to the  
27 PF Tier 1 Equivalent rates and were determined by taking the greater of (1) the Load

1 Shaping rates; or (2) the PF Tier 1 Equivalent rates. See Section 4.1.1.3.1 above for a  
2 description of the Load Shaping rates and Section 5.14 below for a description of the  
3 PF Tier 1 Equivalent rates. The FPS ULS also includes a Demand Charge, which uses the  
4 Demand Rate in the PF, NR, and IP Rate Schedules. The ULS under the FPS-24 Rate  
5 Schedule is specified in GRSP II.M.4. See 2024 Power Rate Schedules and GRSPs, BP-24-A-  
6 02-AP01, GRSPs.

### 8 **5.11 Unauthorized Increase (UAI) Charges**

9 The UAI Charge is a penalty charge to customers taking more power from BPA than they  
10 are contractually entitled to take. The UAI demand rate is 1.25 times the applicable  
11 monthly demand rate. The UAI energy rate is the greater of (1) 150 mills/kWh, or  
12 (2) two times the highest hourly Powerdex Mid-C Index price for firm power for the month.  
13 The monthly cap for UAI charges is the higher of (1) 2,500 mills/kWh, or (2) 1.25 times the  
14 MO's Hard Energy Bid Cap defined in Appendix A of the MO Tariff. See 2024 Power Rate  
15 Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.N.

### 17 **5.12 Residential Exchange Program Settlement Implementation**

18 The 2012 REP Settlement established a fixed stream of financial benefits payable to the  
19 IOUs beginning in FY 2012 and ending in FY 2028. These benefits are allocated among the  
20 IOUs based on their specific ASCs, PFx rates, and eligible residential and farm loads  
21 (Residential Loads). GRSPs II.S and II.T address two issues specific to the implementation  
22 of the 2012 REP Settlement. See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01,  
23 GRSPs.

24  
25 Pursuant to the terms of the 2012 REP Settlement, REP Residential Loads are normally  
26 calculated using a two-year monthly average of the IOUs' eligible residential and farm

1 actual loads. The FY 2024 and 2025 Residential Load monthly averages for each IOU are  
2 from the BP-24 Settlement Agreement (Fredrickson *et al.*, BP-24-FS-BPA-09, Appendix A)  
3 and are listed in the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.S,  
4 Table H.

5  
6 GRSP II.T addresses the recalculation of the PFX rate in the event of a change to an IOU's  
7 ASC. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs. Calculation of  
8 the PFX rate is described in detail in Section 4.1.6 above. The PFX rate calculation is  
9 dependent upon, among other factors, the IOUs' Final ASCs. ASCs are determined outside  
10 the rate proceeding in an ASC Review Process that BPA conducts pursuant to the 2008 ASC  
11 Methodology (ASCM). *See* ASCM, 18 C.F.R. § 301 *et seq.* (2008). Forecast ASCs for  
12 participating IOUs and participating COUs are used for establishing rates in the Initial  
13 Proposal. *See* § 8. Final ASCs are determined coincident with the Final Proposal and are  
14 incorporated therein. An IOU's Final ASC can change after final rates are set, although such  
15 changes are rare. In the event of such a change, the PFX rate must be recalculated for each  
16 REP participating utility. GRSP II.T describes the process for such recalculation. *See* 2024  
17 Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

### 18 19 **5.13 Cost Contributions**

20 In accordance with Section 7(j) of the Northwest Power Act, BPA provides the approximate  
21 cost contributions of different resource categories to BPA's rates for the sale of energy and  
22 capacity. 16 U.S.C. § 839e(j). The rate schedules also indicate the cost of resources BPA  
23 acquires to meet load growth and the relationship of such cost to BPA's average resource  
24 cost. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.Z.



1 **5.14 PF Tier 1 Equivalent Rates**

2 For use in contracts that have rates tied to a traditional PF HLH/LLH rate design without  
3 tiering, the PFp Tier 1 Equivalent rates consist of 12 HLH Energy rates, 12 LLH Energy  
4 rates, and 12 Demand rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load  
5 Shaping rates less a scalar. The scalar is a single mills/kWh value that adjusts the Load  
6 Shaping rates to a level at which the PFp Tier 1 Equivalent Energy rates, in conjunction  
7 with the demand revenue, would collect the Tier 1 revenue requirement allocated to the  
8 PFp Non-Slice loads (the Composite cost pool plus the Non-Slice cost pool). This mills/kWh  
9 value is equivalent to the LSTUR. This calculation is shown in Power Rates Study  
10 Documentation, BP-24-FS-BPA-01A, Table 3.1.8.5. The Demand rates are equal to the  
11 Tier 1 Demand rates. The PF Tier 1 Equivalent rates are subject to adjustment during the  
12 rate period to reflect the Power CRAC, the Power RDC, and the Power FRP Surcharge.  
13 *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.AA.*

14  
15 **5.15 Washington Cap-and-Invest Program Charge**

16 This charge will be applicable if BPA becomes the First Jurisdictional Deliverer (FJD) in the  
17 Washington Cap-and-Invest Program. If BPA elects to be the FJD, BPA presumes that  
18 customers will 1) register to receive no-cost allowances from the Washington Department  
19 of Ecology and 2) transfer to BPA their no-cost allowances that they receive from the  
20 Washington Department of Ecology for emissions forecasted for Federal power deliveries.  
21 If this does not occur, the customer will be subject to the new rate and charged for the cost  
22 that BPA incurs purchasing allowances to cover emissions for Federal service to its load  
23 plus a 25 percent cost adder. *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-*  
24 *AP01, GRSP II.AB.*

1 **5.16 Resource Adequacy Service**

2 This service will be applicable when BPA begins participation in the Western Resource  
3 Adequacy Program (WRAP) 3B Binding Program and elects a binding summer 2025 season  
4 (June 2025 through September 2025). The Resource Adequacy Service includes two  
5 components (1) a 2.73 mills/kWh credit for Load Following customers that use non-  
6 Federal resources to serve Above-RHWM Load that meet the WRAP forward-showing  
7 qualifying capacity capability (QCC) requirements, and (2) a 2.73 mills/kWh charge for  
8 Load Following customers with NLSLs that do not submit to BPA an approved exclusion  
9 attestation for the NLSL or provide QCC resource information for any non-Federal  
10 resources serving the NLSL. *See 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01,*  
11 *GRSP II.AC.*

## 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 Delivery Charge, (2) the Transfer Service Operating Reserve Charge, (3) the Transfer Service Regulation and Frequency Response Charge, and (4) the Transfer Service Regional Compliance Enforcement Charge. *See* 2024 Power Rate Schedules and General Rate Schedule Provisions, BP-24-A-02-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 points of delivery, 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.*

1 **6.3 Transfer Service Delivery Charge**

2 The Transfer Service Delivery Charge (TSDC) in Power GRSP II.L.1 is a charge for low-  
3 voltage delivery service of Federal power provided under non-Federal transmission service  
4 agreements over a third-party transmission system. *Id.* at GRSP II.L.1. The TSDC applies to  
5 power customers that take delivery at voltages below 34.5 kV unless such costs have been  
6 directly assigned to the specific customer. The TSDC is a dollars-per-kilowatthour rate  
7 levied on customer load at the customer’s low-voltage points of delivery (POD) at the time  
8 of that customer’s system peak. Calculation of the rate is described below.

9  
10 **6.3.1 Transfer Service Delivery Rate Revenue Requirement**

11 The revenue requirement for the Transfer Service Delivery rate is computed by compiling  
12 the total low-voltage distribution, use of facility, and delivery charges paid by Power  
13 Services to third-party transmission providers in each of FY 2021 and FY 2022. Any known  
14 changes for the FY 2024-2025 rate period are added and the average calculated for  
15 FY 2021 and FY 2022.

16  
17 BPA’s total average cost for low-voltage delivery for FY 2021-2022 is \$ \$2,634,316. Power  
18 Rates Study Documentation, BP-24-FS-BPA-01A, Table 6.1.

19  
20 **6.3.2 Transfer Service Delivery Forecast Load**

21 The average of FY 2021 and FY 2022 customer system peaks is determined by reviewing  
22 customer bills and extracting customer load data for the low-voltage PODs at the time of  
23 each customer’s system peak. The average of the FY 2021 and FY 2021customer system  
24 peaks is 2,358,445 kW. *Id.*

1 **6.3.3 Transfer Service Delivery Rate Calculation**

2 To calculate the Transfer Service Delivery rate for FY 2024-2025, as shown below, the  
3 adjusted FY 2021-2022 average revenue requirement is divided by the average  
4 FY 2021-2022 customer system peak:

|   |                                                       |                   |
|---|-------------------------------------------------------|-------------------|
| 5 | Distribution, Use-of-Facility, and Low-Voltage Costs: | \$2,634,316       |
| 6 | BPA Customer System Peak:                             | 2,358,445 kW      |
| 7 | Transfer Service Delivery Rate FY 2024-2025:          | \$1.12 per kW/mo. |

8 *Id.*

9  
10 **6.4 Transfer Service Operating Reserve Charge**

11 The Transfer Service Operating Reserve Charge is designed to compensate BPA for the cost  
12 of acquiring operating reserves assessed by third-party transmission providers and non-  
13 BPA balancing authorities for service to transfer service customers' loads.

14  
15 Assessment of the Transfer Service Operating Reserve Charge is conditioned on the  
16 satisfaction of two criteria:

- 17 (1) BPA serves the power customer by transfer service; and
- 18 (2) the transfer service customer is not already paying BPA for operating  
19 reserves for the customer's load under the ACS-24 rate schedule.

20  
21 The Transfer Service Operating Reserve rates are the same as the ACS-24 rates for  
22 operating reserves that BPA charges customers that have load in the BPA balancing  
23 authority area (BAA); *i.e.*, the Transfer Service Spinning Operating Reserve rate is equal to  
24 the ACS-24 Operating Reserve – Spinning Reserve Service rate, and the Transfer Service  
25 Supplemental Operating Reserve Charge is equal to the ACS-24 Operating Reserve –  
26 Supplemental Reserve Service rate. The monthly billing determinant for both Transfer

1 Service Operating Reserves Charges is the amount of the customer’s metered load served  
2 by transfer (non-BPA BAA load).

3  
4 To compute a revenue forecast for these charges, the forecast TRL of BPA customers served  
5 under Transfer Service is aggregated for each Transfer Service provider. These loads are  
6 responsible for operating reserves charges (spinning and supplemental) and are applied to  
7 transfer service customers in the same manner as operating reserves are applied to  
8 directly connected customers under ACS-24.

### 9 10 **6.5 Transfer Service Regulation and Frequency Response Charge**

11 The Transfer Service Regulation and Frequency Response Charge is designed to  
12 compensate BPA for the cost of acquiring regulation and frequency response service  
13 assessed by third-party transmission providers and non-BPA BAAs for service to transfer  
14 service customers’ loads.

15  
16 Assessment of the Transfer Service Regulation and Frequency Response Charge is  
17 conditioned on the satisfaction of two criteria:

- 18 (1) BPA serves the power customer by transfer service; and
- 19 (2) the transfer service customer is not already paying BPA for regulation and  
20 frequency response for the customer’s load under the ACS-24 rate schedule.

21  
22 The Transfer Service Regulation and Frequency Response rate is equal to the ACS-24 rate  
23 for regulation and frequency response that BPA charges customers with load in the BPA  
24 BAA. The monthly billing determinant for the Transfer Service Regulation and Frequency  
25 Response Charge is the amount of the customer’s metered load served by transfer  
26 (non-BPA BAA load).

1 To compute a revenue forecast for these charges, the forecast TRL of BPA customers served  
2 under Transfer Service is aggregated for each Transfer Service provider. These loads are  
3 billed at the ACS-24 Regulation and Frequency Response rate.  
4

## 5 **6.6 Revenue Received from Transfer Service Charges**

6 Revenue received from Transfer Service Charges includes the TSDC, along with forecast  
7 revenues associated with Transfer Service Operating Reserve and Regulation and  
8 Frequency Response service, and any other charges for regional compliance as outlined in  
9 Section 6.7 below. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A,  
10 Table 2.3.1.5, line 234. These revenues offset the ancillary service costs Power Services  
11 will pay to third-party transmission systems for providing similar services, which are  
12 included as a cost in the Power Revenue Requirement. *See* Power Rates Study  
13 Documentation, BP-24-FS-BPA-01A, Table 2.3.1.2, lines 53-55.  
14

## 15 **6.7 Transfer Service Regional Compliance Enforcement Charge**

16 The Transfer Service Regional Compliance Enforcement Charge applies to all transfer  
17 service customer loads located outside of the BPA BAA. The Transfer Service Regional  
18 Compliance Enforcement Charge is a separate stand-alone charge.  
19

### 20 **6.7.1 Background on Regional Compliance Enforcement Charge**

21 The Regional Compliance Enforcement Charge recovers costs associated with funding the  
22 North American Electric Reliability Organization (NERC) and the regional entity, which is  
23 the Western Electricity Coordinating Council (WECC). WECC develops and assesses a  
24 charge to loads located in BAAs within the Western Interconnection to support its regional  
25 operations. The charge is based on a Net Energy for Load (NEL) value, which includes all  
26 loads within a balancing authority area, including system losses. Each BAA submits its NEL

1 to WECC yearly. WECC adds the NEL amounts for all BAAs to identify a total NEL for all  
2 loads in the Western Interconnection. The annual revenue requirement for WECC is then  
3 divided by the total NEL to establish a \$/MWh assessment.  
4

### 5 **6.7.2 Regional Compliance Enforcement Assessment**

6 The Regional Compliance Enforcement Charge is assessed to the individual loads identified  
7 in the NEL data submitted by the balancing authority areas. The format of each BAA's NEL  
8 submission to WECC varies across the region; *e.g.*, some BAAs identify each individual  
9 customer load in their NEL submissions, including both native and non-native load. In the  
10 past for these BAAs, WECC would issue an invoice to each customer for WECC Charges.

11 Other BAAs identify and submit single load quantities for their BAAs, with no  
12 differentiation between native and non-native loads. In these instances, the BAA receives a  
13 single invoice from WECC for all loads in the BAA. BPA's transfer service customer loads  
14 are located in BAAs that report in both manners.  
15

### 16 **6.7.3 BPA's Transfer Services Regional Compliance Enforcement Charge**

17 For FY 2024-2025, WECC will bill Power Services for all NEL quantities reported by the  
18 BAAs that are associated with transfer service customer loads outside the BPA BAA. BPA  
19 will recover this billed amount from all transfer service customer loads located outside of  
20 the BPA BAA through the Transfer Service Regional Compliance Enforcement Charge,  
21 regardless of how each BAA reports the transfer service customer's load in its NEL  
22 submission.  
23



1 **6.7.4 Regional Compliance Enforcement Charge**

2 **6.7.4.1 Regional Compliance Enforcement Revenue Requirement**

3 To forecast the BPA revenue requirement for the Transfer Service Regional Compliance  
4 Enforcement rate, total NEL reported to WECC is computed for BPA transfer service  
5 customer loads outside BPA's BAA. The 2022 WECC NEL assessment list is used to identify  
6 specific transfer service customers by name, their corresponding NEL amounts, and NEL  
7 amounts associated with only BPA by the reporting BAAs. All of these NEL amounts are  
8 then summed to establish a total transfer service NEL value. The NEL quantities include  
9 losses, as do the NEL quantities WECC uses to assess its charges. The 2022 WECC NEL  
10 assessment is based on 2021 load information, which is the most current information  
11 available for forecasting BPA's WECC assessment for transfer service customers for  
12 FY 2024-2025.

13  
14 The revenue requirement for the Transfer Service Regional Compliance Enforcement rate  
15 is \$312,380 and is computed by summing all individual assessment amounts as calculated  
16 by WECC and given to BPA. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
17 Table 6.1.

18  
19 **6.7.4.2 Regional Compliance Enforcement Rate Calculation**

20 The Transfer Service Regional Compliance Enforcement rate is computed by dividing the  
21 above revenue requirement by the total of all BPA transfer service customers' load from  
22 outside the BPA BAA. All non-BPA BAA transfer service customer loads are included,  
23 regardless of NEL reporting standards. For FY 2024-2025 this quantity of 6,278,383 MWh  
24 is used to calculate the Transfer Service Regional Compliance Enforcement rate of  
25 0.05 mills/kWh.

1 **6.8 Southeast Idaho Load Service Cost Allocation**

2 From 1989 to 2016, BPA used an exchange agreement with PacifiCorp and a transmission  
3 wheeling agreement to deliver power to BPA’s preference customers in Southeast Idaho.  
4 The exchange agreement with PacifiCorp expired in June 2016. Because of limited  
5 transmission capability between BPA’s system and BPA’s Southeast Idaho customers, BPA  
6 entered into five-year market purchases as part of an interim plan of service for a portion  
7 of BPA’s transfer customer load located in Southeast Idaho. The first interim plan of service  
8 included two, five-year fixed-price market purchases from July 2016 through June 2021.  
9 The second interim plan of service included five-year market purchases based at index  
10 beginning July 2021 through June 2026.

11  
12 Due to the index pricing structure of these purchases, for FY 2021-2026, costs will not be  
13 allocated to the Composite cost pool as in the BP-20 rate case where a fixed market price  
14 was used to determine the delta between the forward market and the price at which the  
15 purchases were made. In the previous five year interim service plan, the fixed price of the  
16 market purchases, less a market delta (difference) was allocated to balancing purchases,  
17 which are assigned to the Non-Slice cost pool. The remaining cost of the purchases, the  
18 market delta, was allocated to the transfer service budget, which is a component of the  
19 Composite cost pool.

20  
21 For the five-year interim service plan, starting in July 2021, BPA has acquired market  
22 purchases based at index. One market index purchase includes an adder to the Mid-C  
23 index. An adder is a fixed amount of additional dollars added to the Mid-C Index at the time  
24 energy is delivered. Therefore, if at the time of delivery the Mid-C index was \$35 and the  
25 adder was \$2, then the total transaction price would be \$37 for that interval. The second  
26 index purchase includes a Mid-C minus component. Using the example above, and

1 replacing the adder with a minus component, the result of the total transaction price for  
2 that interval would be \$33. When we net the adder and minus component together by  
3 multiplying the hours, megawatts, and index addition or subtraction for each contract there  
4 is a net benefit of \$663,380. Unlike the first interim service plan where the fixed price  
5 resulted in a market delta cost, the offsetting nature of the Mid-C index adder and minus  
6 component results in no added cost to BPA related to these market purchases. Since there  
7 is no added cost, the full result will be included in the Non-Slice cost pool.

8

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1 **7. SLICE TRUE-UP**

2  
3 **7.1 Slice True-Up Adjustment**

4 Slice customers are subject to an annual Slice True-Up Adjustment for expenses, revenue  
5 credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool.  
6 The annual Slice True-Up Adjustment will be calculated for each fiscal year as soon as  
7 BPA's audited actual financial data are available (usually in November). *See* TRM, BP-12-  
8 A-03, § 2.7.

9  
10 **7.2 Composite Cost Pool True-Up**

11 The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment  
12 for the Composite cost pool for each fiscal year. For each Slice customer, the annual Slice  
13 True-Up Adjustment Charge for the Composite cost pool will be calculated as shown in the  
14 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.R.1. The dollar amount  
15 calculated may be positive or negative. The Composite Cost Pool True-Up Table shows the  
16 forecast expenses, revenue credits, and adjustments that form the basis for the Slice True-  
17 Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. *Id.* at  
18 GRSP II.R, Table F.

19  
20 The following sections discuss the treatment of certain expenses, revenue credits, and  
21 adjustments included in the Composite Cost Pool True-Up.

22  
23 **7.2.1 System Augmentation Expenses**

24 System augmentation expenses are included in the FY 2024-2025 Composite cost pool.  
25 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 RHHM)**

2 The Firm Surplus and Secondary Adjustment (from Unused RHHM) is subject to the  
3 Composite Cost Pool True-Up. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-  
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* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-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-24 rates. The forecast interest credit  
22 for the Composite cost pool is \$2.274 million in FY 2024 and \$3.199 million in FY 2025. *See*  
23 *Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 2.3.1.3.*  
24

25 The interest credit on the financial reserves amount is subject to the Composite Cost Pool  
26 True-Up. The actual interest credit calculated on the revised base amount of financial



1 reserves can change from the forecast interest credit if there are changes in the factors  
2 used to calculate the forecast interest credit.

### 4 **7.2.6 Bad Debt Expenses**

5 Bad debt expenses, if any, are allocated between the Composite cost pool and the Non-Slice  
6 cost pool, as specified in the TRM, BP-12-A-03, Table 2A. There is no forecast bad debt  
7 expense for the FY 2024-2025 period for ratemaking purposes. If a bad debt expense is  
8 identified and accounted for in BPA's actual audited financial reports for a given fiscal year,  
9 BPA will determine whether the expense should be included in the actual expenses and  
10 revenue credits that are allocable to the Composite cost pool in the applicable fiscal year of  
11 the rate period. If so, then the expense may be included for purposes of the Composite Cost  
12 Pool True-Up, and the bad debt expense would be allocated according to the principle of  
13 cost causation, as described generally in the TRM, BP-12-A-03, Section 2.1.

14  
15 Any bad debt expense associated with a sale to any customer that purchased Federal power  
16 exclusively at the FPS-22 and FPS-24 rates would be excluded for Composite Cost Pool  
17 True-Up purposes. Bad debt expenses associated with sales of power at only these FPS  
18 rates are related solely to BPA's sales of surplus power after the inception of the Slice  
19 product and not to sales of requirements power. The expenses and revenues from such  
20 sales are included in the Non-Slice cost pool. *See* TRM, BP-12-A-03, § 2.2.3.

21  
22 Any bad debt expense associated with a sale to a customer that purchases power at only  
23 the PF or IP rate will be included for purposes of the Composite Cost Pool True-Up. The  
24 allocation to the Composite cost pool of any bad debt expense associated with a sale to a  
25 customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer

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

3  
4 Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up  
5 purposes if Slice customers paid for the bad debt expense through their Slice True-Up  
6 Adjustment Charge.

### 7 8 **7.2.7 Settlement and Judgment Amounts**

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

### 15 16 **7.2.8 Transmission Costs for Designated BPA System Obligations**

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

22  
23 Transmission reservations are set aside for non-discretionary obligations (*e.g.*, Designated  
24 BPA System Obligations). Because Power Services does not know the actual amounts of  
25 transmission usage until the preschedule period for such obligations, the transmission  
26 reservations for those obligations are purchased based on the maximum need for the year.

1 Therefore, the forecast cost of the reservations for Designated BPA System Obligations is  
2 included in the Composite cost pool, and such costs are not subject to the Composite Cost  
3 Pool True-Up.

4  
5 Any revenues from the resale of transmission that appear to be the result of BPA sales of  
6 unused transmission inventory associated with set-aside transmission will be excluded for  
7 Composite Cost Pool True-Up purposes. Because the cost of additional transmission  
8 purchased (or of using Non-Slice transmission inventory) to serve Designated BPA System  
9 Obligations in excess of what was forecast in the ratemaking process is not included in the  
10 Composite Cost Pool True-Up, revenues from sales of surplus transmission inventory also  
11 are excluded from the Composite Cost Pool True-Up.

### 12 13 **7.2.9 Power Services Third-Party Transmission and Ancillary Services**

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

### 19 20 **7.2.10 Transmission Loss Adjustment**

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

1 **7.2.11 Resource Support Services Revenue Credit**

2 A credit for RSS revenue is included in the Composite cost pool. The credit is for revenues  
3 earned by uses of capacity to support resources that receive RSS. *See* § 3.2.3.1.3 above.

4 This revenue credit is not subject to the Composite Cost Pool True-Up.  
5

6 **7.2.12 Generation Inputs for Ancillary and Other Services Revenue Credit**

7 The uses of the generating capacity available to BPA to support the transmission system  
8 and maintain reliability are generally referred to as generation inputs. Generation inputs  
9 include capacity-related and energy-related services that BPA uses to provide Ancillary and  
10 Control Area Services, support transmission, and maintain the reliability of the  
11 transmission system. These services include balancing reserve services, operating reserve  
12 services, synchronous condensing, generation dropping, redispatch service, station service,  
13 and U.S. Army Corps of Engineers (Corps)/Reclamation segmentation. A credit for  
14 Generation Inputs revenue is included in the Composite cost pool. *See* TRM, BP-12-A-03,  
15 Table 2, line 120, and Table 3.4, line 44. This revenue credit is subject to the Composite  
16 Cost Pool True-Up Table. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A,  
17 Table 9.3.  
18

19 **7.2.13 Tier 2 Rate Adjustments**

20 Tier 2 rate adjustments are ratemaking adjustments to the Composite cost pool to reflect a  
21 share of expenses incurred by Power Services that are allocable to all power sold. *See*  
22 § 3.2.2 above. There are two types of rate adjustments: the Tier 2 overhead cost adder and  
23 the Tier 2 transmission scheduling service cost adder.  
24

25 The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by  
26 Power Services. *See* § 3.2.2.3. The Tier 2 overhead cost adder is included in the Composite

1 cost pool. This adjustment is estimated for ratemaking purposes and is not subject to the  
2 Composite Cost Pool True-Up.

3  
4 The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative  
5 costs incurred by Power Services. For a description of this adjustment, see Section 3.2.2.2  
6 above. The forecast of this adjustment is included in the RSS revenue credit. This  
7 adjustment is not subject to the Composite Cost Pool True-Up.

#### 9 **7.2.14 Residential Exchange Program Expense**

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

#### 15 **7.2.15 Canadian Designated System Obligation Annual Financial Settlements**

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

1 month of September of the same fiscal year are charged or credited to other power  
2 purchases, and Slice customers pay their share of the charge or receive their share of the  
3 credit through the Composite Cost Pool True-Up Table.

#### 4 **7.2.16 Participating Resource Scheduling Coordinator (PRSC) Net Credit**

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

21 The PRSC Net Credit is forecast to be \$0 in FY 2024 and FY 2025 and is subject to the  
22 Composite Cost Pool True-Up. The amount calculated as part of the True-Up process may  
23 be a negative number (a charge).

1 **7.2.17 Other Potential Adjustments**

2 No changes have been made to the Composite Cost Pool True-Up Table in the BP-24 rate  
3 proceeding. *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSP II.R.

4

5 **7.3 Slice Cost Pool True-Up**

6 The Slice Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for  
7 the Slice cost pool, as described in TRM, BP-12-A-03, Section 2.7.2. Calculation of the  
8 Annual Slice Cost Pool True-Up is described in GRSP II.R.2 and is shown in GRSP Table G.

9 *See* 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01. Slice expenses and credits  
10 are forecast to be zero in FY 2024 and FY 2025. If there are any actual Slice expenses and  
11 credits incurred during the rate period, such expenses and credits will be subject to the  
12 Slice Cost Pool True-Up.

13

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## 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 (\$/MWh) or mills per kilowatthour (mills/kWh)) 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, RAM2024 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 Residential Exchange Program Settlement Implementation Agreements (REPSIA) and with COU participants through Residential Purchase and Sale Agreements (RPSA). Total REP costs are included in rates for FY 2024-2025.

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,

1 REP-12-A-02A. Individual IOU REP benefit determinations under the 2012 REP Settlement  
2 will continue to be calculated as under the traditional REP; that is, BPA will compare each  
3 IOU's ASC for FY 2024-2025 with its respective BP-24 PFX rate and, if the difference is  
4 positive, multiply the difference by the IOU's exchange load to calculate its REP benefit (in  
5 dollars). *Id.* Similarly, pursuant to the RPSAs with the two COUs participating in the REP,  
6 BPA will compare each COU's ASC for FY 2024-2025 with its respective BP-24 PFX rate and,  
7 if the difference is positive, multiply the difference by its exchange load to calculate its REP  
8 benefit. The COUs' REP benefits are in addition to (*i.e.*, are not included in) the fixed stream  
9 of IOU REP benefits under the 2012 REP Settlement. *Id.* For a forecast of individual utility  
10 annual REP benefit payments for FY 2024-2025, see Table 6 of this Study.

## 11 12 **8.2 ASC Determinations**

13 BPA determines participating utilities' ASCs outside the rate proceeding in an ASC Review  
14 Process conducted pursuant to the substantive and procedural requirements of the 2008  
15 ASC Methodology (ASCM), 18 C.F.R. § 301, *et seq.* The Federal Energy Regulatory  
16 Commission granted final approval to the 2008 ASCM on September 4, 2009. As part of the  
17 BP-24 rates settlement process, BPA and REP-utilities agreed to a condensed ASC Review  
18 Process in order to finalize FY 2024-2025 ASCs prior to publication of the BP-24 Initial  
19 Proposal. *See* Fredrickson *et al.*, BP-24-FS-BPA-09, Appendix A, Attachment 1

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

1 Under the 2008 ASCM, the ASC for each utility may change if the utility adds a new  
2 resource, retires an existing resource, or adds an NLSL. However, under the 2012 REP  
3 Settlement, participating IOUs agreed not to submit ASC revisions based on new resources  
4 coming on line or being removed during the Exchange Period (the Exchange Period is the  
5 same as the rate period, currently FY 2024-2025). 2012 REP Settlement, REP-12-A-02A,  
6 § 6.4. Therefore, for COUs only, the ASC may change if the utility adds a new resource or  
7 retires an existing resource during the Exchange Period. The revised ASC takes effect in the  
8 month after a new resource comes on line, an existing resource is retired, or a new NLSL  
9 begins taking service. The ASCs for the BP-24 rate period are shown in Table 8.1 of the  
10 Power Rates Study Documentation, BP-24-FS-BPA-01A.

11  
12 Under the 2012 REP Settlement, the IOU ASCs that are effective on the first day of the rate  
13 period will continue to be in effect throughout the Exchange Period, with the exception of  
14 the addition of an NLSL. 2012 REP Settlement Agreement, REP-12-A-02A. These “day-one”  
15 IOU ASCs are developed for use in establishing rates for the BP-24 rate period. Section II.T  
16 of the 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, specifies how the PFX rate  
17 applicable to each REP participant will change if a revised ASC takes effect.

18  
19 The ASCs used in the BP-24 Initial Proposal were determined in the separate ASC Review  
20 Processes and published in the Final ASC Reports on October 28, 2022. The ASCs reflected  
21 in the Final ASC Reports were based on REP Staff’s assessment of the utilities’ ASCs filings.  
22 BPA issued Final ASC Reports for eight utilities: Avista Utilities, Idaho Power Company,  
23 NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark  
24 County PUD, and Snohomish County PUD. These reports are available at:  
25 [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)  
26 [utility-filings.](https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings)

1 **8.3 Residential Exchange Program Load**

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

4  
5 Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical  
6 average for determining monthly exchange load, referred to as Residential Load, to  
7 calculate IOU REP benefits. 2012 REP Settlement, REP-12-A-02A, § 2 (“Residential Load”).

8 For the BP-24 rate period, the historical years are calendar year (CY) 2021 and CY 2022.

9 As part of the BP-24 Rates and ASC Review Process Settlements, BPA will hold the  
10 Residential Loads for August-December 2022 equal to the Residential Loads from August-  
11 December 2021. The monthly loads applicable to both years of the BP-24 rate period are  
12 shown in GRSP I.I.S, Table H. 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01,  
13 GRSPs.

14  
15 The COUs’ RPSAs do not specify the use of historical exchange loads in computing COU REP  
16 benefits; therefore, forecasts are used to estimate COU REP benefits for ratemaking  
17 purposes. For the COUs, the FY 2024-2025 exchange load forecasts are based on the  
18 exchange load information provided by the COUs in the ASC Review Process. Each COU’s  
19 exchange load forecast is adjusted for the COU’s Tier 1 percentage (if applicable), as  
20 required by the TRM. The Tier 1 percentage is defined as BPA’s forecast percentage of the  
21 COU’s load that is expected to be served by purchases of power at Tier 1 rates from BPA  
22 and from the COU’s Existing Resources for CHWM. COU REP benefits will be paid on actual  
23 residential and farm sales as adjusted by the Tier 1 percentage for each COU, as submitted  
24 after each month during the rate period. The monthly IOU Residential Loads and monthly  
25 forecast COU exchange loads are shown in Table 8.2 of the Power Rates Study  
26 Documentation, BP-24-FS-BPA-01A.

1 **8.4 REP 7(b)(3) Surcharge Adjustment**

2 The REP § 7(b)(3) surcharge is a utility-specific addition to the base PFx rates that recovers  
3 each REP participant's allocated share of rate protection provided pursuant to § 7(b)(2) of  
4 the Northwest Power Act. 16 U.S.C. § 839e(b)(2)-(3). Each REP participant's initial 7(b)(3)  
5 surcharge is determined in the § 7(i) rate proceeding based on the base PFx rates, the ASCs,  
6 and the forecast exchange loads of all utilities assumed for ratemaking to participate in the  
7 REP. *Id.* at § 839e(i). Each REP participant's initial 7(b)(3) surcharge is displayed in  
8 Section 6.1 of the PF-24 rate schedule. 2024 Power Rate Schedules and GRSPs, BP-24-A-  
9 02-AP01, PF-24, § 6.1. Each participating utility's 7(b)(3) surcharge is subject to change  
10 during the rate period if any participant's ASC changes during the rate period due to the  
11 addition of an NLSL in the utility's service territory. For COUs only, the addition or removal  
12 of a resource from the participant's resource portfolio will also change its 7(b)(3)  
13 surcharge. The procedures for modifying the 7(b)(3) surcharges of all REP participants are  
14 codified in GRSP II.T. 2024 Power Rate Schedules and GRSPs, BP-24-A-02-AP01, GRSPs.

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## 9. REVENUE FORECAST

The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2024-2025, and the current fiscal year, FY 2023. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect (BP-22 rates), and the second uses proposed rates (BP-24 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-24-FS-BPA-02, §§ 3.2-3. Both forecasts are based on the Power Loads and Resources Study, BP-24-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 2023-2025 and discussed in Section 9.5 below.

The revenue forecast includes revenue calculations for the current fiscal year, FY 2023, 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-24-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) 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 seven 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;
- 6 3. Scheduling products under the FPS rate, described in Section 9.1.3;
- 7 4. Short-term market sales, described in Section 9.1.4;
- 8 5. Long-term contractual obligations, described in Section 9.1.5;
- 9 6. Canadian entitlement returns, described in Section 9.1.6; and
- 10 7. Other sales, described in Section 9.1.7.

11  
12 **9.1.1 Priority Firm Power Sales under CHWM Contracts**

13 For FY 2023, the revenues from PF power sales pursuant to CHWM contracts are calculated  
14 using the product of (1) forecast loads documented in the Power Loads and Resources  
15 Study, BP-24-FS-BPA-03, Section 2.2, and accompanying Power Loads and Resources  
16 Documentation, BP-24-FS-BPA-03A, Table 1.2.1 for energy, Table 1.2.2 for HLH, and  
17 Table 1.2.3 for LLH; and (2) PF-22 rates. Revenues from PF sales pursuant to CHWM  
18 contracts for FY 2023 are listed in Table 4 of this Study, lines 3-12, and in Power Rates  
19 Study Documentation, BP-24-FS-BPA-01A, Table 9.2, lines 3-12.

20  
21 For FY 2024 and FY 2025, revenues from PF sales pursuant to CHWM contracts are  
22 computed using the product of (1) forecast loads assuming normal weather, documented in  
23 the Power Loads and Resources Study, BP-24-FS-BPA-03, and accompanying Power Loads  
24 and Resources Documentation, BP-24-FS-BPA-03A; and (2) the appropriate PF rates  
25 derived by RAM2024. Inputs and results for the revenue forecast are managed and  
26 calculated pursuant to the CHWM contracts using the Revenue Forecasting Application



1 (RFA). Revenues are reported for Tier 1 Customer charges (Composite, Slice, and Non-  
2 Slice), Load Shaping, and Demand, including the Low Density Discount and Irrigation Rate  
3 Discount Credits, and any additional Tier 2 and/or RSS charges.  
4

#### 5 **9.1.1.1 Composite and Non-Slice Customer Charges**

6 Revenues from each customer for the Composite and Non-Slice Customer Charges are  
7 based on the customer's TOCA and the customer's contractually specified products. There  
8 are no Slice charges for FY 2023-2025. Revenues obtained from the Composite and Non-  
9 Slice Customer Charges represent the majority of revenues from firm power sales under  
10 CHWM contracts for FY 2023-2025. The calculation of forecast Composite and Non-Slice  
11 revenues is shown in Power Rates Study Documentation, BP-24-FS-BPA-01A,  
12 Tables 3.1.6.1-3. Composite and Non-Slice revenues for FY 2023-2025 are listed in Table 4  
13 of this Study, lines 3-4, and Power Rates Study Documentation, BP-24-FS-BPA-01A,  
14 Table 9.2, lines 3-4.  
15

#### 16 **9.1.1.2 Load Shaping Charge**

17 The Load Shaping Charge reflects the costs and benefits of shaping the Tier 1 System  
18 Capability to the monthly/diurnal shape of a customer's below-RHWM load. A charge to  
19 the customer results when the customer's shaped load is greater than its share of the Tier 1  
20 System Output in any month for both HLH and LLH; the customer receives a credit from  
21 BPA when the opposite occurs. The Load Shaping Charge is described in Section 4.1.1.3  
22 above. The forecast of Load Shaping revenues for FY 2023-2025 is listed in Table 4 of this  
23 Study, line 6, and Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2, line 6.  
24

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 2023-2025, 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 2023-2025 is also shown in Table 4 of this  
9 Study, line 7, and Power Rates Study Documentation, BP-24-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-24-A-02-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 2023-2025 are listed in Table 4 of this Study, line 8, and Power Rates Study  
20 Documentation, BP-24-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-24-A-02-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 2023-2025 are listed in Table 4 of this Study, line 9, and Power  
3 Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2, line 9.

#### 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 2023-2025 are  
9 listed in Table 4 of this Study, line 10, and Power Rates Study Documentation, BP-24-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 2023-2025 are listed in Table 4 of this Study, line 11, and Power Rates Study  
14 Documentation, BP-24-FS-BPA-01A, Table 9.2, line 11.

#### 16 **9.1.2 Industrial Firm Power Sales (IP) to Direct Service Industrial Customers 17 (DSI)**

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-24-FS-  
20 BPA-03, Section 2.4, and accompanying Power Loads and Resources Documentation, BP-  
21 24-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 RAM2024. For FY 2023, the revenues for DSI customers are  
23 calculated using the IP-22 rate. Forecast IP revenues for FY 2023-2025 are listed in Table 4  
24 of this Study, line 14, and Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2,  
25 line 14.

1 **9.1.3 Products and Services under the FPS Rate**

2 During FY 2023-2025, BPA is providing power products and services under the FPS rate  
3 described in Section 4.4 of this Study. Revenues from the products and services are  
4 derived by multiplying individual customer billing determinants by the appropriate  
5 FPS rate. Forecast FPS revenues for FY 2023-2025 are listed in Table 4 of this Study,  
6 line 15, and Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2, line 15.

7  
8 **9.1.4 Short-Term Market Sales**

9 The revenue forecast includes revenues from the sale of surplus energy, which can be a  
10 combination of secondary energy and firm energy in excess of that required to serve firm  
11 loads. The wholesale market price effects of a number of factors are considered in  
12 determining the forecast of surplus sales revenue. For FY 2023, the surplus energy  
13 revenue included in the revenue forecast consists of the average of the surplus energy  
14 revenues in forecast months computed during RevSim simulations of 40 games for each of  
15 30 historical water years, for a total of 2,700 games. For FY 2023-2025, the surplus energy  
16 revenue is the median of the surplus energy revenues across those 2,700 games. In  
17 addition, BPA includes a credit to account for the incremental value of marketing power to  
18 extra-regional points of delivery. *See* Power and Transmission Risk Study, BP-24-FS-  
19 BPA-05, § 4.1.1.2.3.

20  
21 The revenue forecast for short-term market sales is computed using RevSim to calculate  
22 monthly HLH and LLH energy surpluses for each of the 2,700 games, applying  
23 corresponding market prices developed for each game. Additionally, the short-term  
24 market sales forecast contains revenue from contract sales for FY 2023-2025. The contract  
25 sales portion consists of DSI sales and sales outside the Pacific Northwest. *See* Power and  
26 Transmission Risk Study, BP-24-FS-BPA-05, § 4.1.1.2.3. Revenues for FY 2023-2025 are

1 shown in Table 4 of this Study, line 16, and Power Rates Study Documentation, BP-24-FS-  
2 BPA-01A, Table 9.2, line 16.

### 3 4 **9.1.5 Long-Term Contractual Obligations**

5 Long-term obligation contracts include a wind energy exchange and capacity and energy  
6 exchanges. For FY 2023-2025, revenue from these contractual obligations is calculated  
7 pursuant to the individual contracts and then summed and added to the forecast as a  
8 group. BPA has long-term contracts to provide energy and capacity. Each contract is an  
9 advanced noticed right to power. See the Power and Transmission Risk Study, BP-24-FS-  
10 BPA-05, for more information. Forecast revenue for FY 2023-2025 is listed in Table 4 of  
11 this Study, line 17, and Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2,  
12 line 17.

### 13 14 **9.1.6 Canadian Entitlement Return**

15 The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the  
16 border pursuant to Columbia River Treaty between Canada and the U.S. No revenues are  
17 generated from the delivery of this power, but energy amounts are listed in the revenue  
18 forecast to represent this system obligation. The average megawatt deliveries for FY 2023-  
19 2025 are listed in Table 4 of this Study, line 18, and Power Rates Study Documentation,  
20 BP-24-FS-BPA-01A, Table 9.2, line 18.

### 21 22 **9.1.7 Other Sales**

23 Other Sales include forecast revenues from primarily the Slice True-Up and Load Shaping  
24 True-Up, which are applicable only for FY 2023. The forecast of Other Sales revenue for  
25 FY 2023-2025 is listed in Table 4 of this Study, line 19, and Power Rates Study  
26 Documentation, BP-24-FS-BPA-01A, Table 9.2, line 19.

1 **9.2 Revenue Forecast for Miscellaneous Revenues**

2 Miscellaneous Revenues include revenues from the Transfer Service Charges, Energy  
3 Efficiency, Downstream Benefits, Reclamation power for irrigation, and the Upper Baker  
4 project.

5  
6 The Transfer Service revenue forecast accounts for costs of the delivery of Federal power  
7 over non-Federal transmission systems and is described in § 6 of this Study. Included in  
8 the Transfer Service revenue forecast are revenues from the Transfer Service Delivery  
9 Charge, Operating Reserve Charge, Regulation and Frequency Response Charge, and  
10 Regional Compliance Enforcement Charge as described in Sections 6.3-6.6.

11  
12 Energy Efficiency revenues are received by BPA as reimbursements for costs relating to  
13 implementation of various energy efficiency projects. For FY 2023-2025, revenues from  
14 Energy Efficiency are calculated by estimating project expenses. While these revenues are  
15 wholly offset by the associated expenses, which are recorded on the expense ledger, the  
16 expenses are included in the revenue requirement; therefore, the revenues are included in  
17 this forecast. The Energy Efficiency revenue credit concludes after FY 2023 upon  
18 termination of the Energy Efficiency Development Program,

19  
20 Downstream Benefits are revenues BPA receives from utilities that benefit from the  
21 coordinated planning and operation of Corps and Reclamation upstream storage reservoirs  
22 as part of the Pacific Northwest Coordination Agreement. 62 Fed. Reg. 40,512 (July 7,  
23 1997). For FY 2023-2025, revenues from downstream benefits are estimated by applying a  
24 three-year average from the three most recent studies of downstream benefits conducted  
25 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 2023-2025 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 2023-2025 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 2023-2025 are listed in Table 4 of this Study, line 21, and  
19 Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2, lines 21-28.

### 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-24-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-24-FS-BPA-01A, Table 9.2, line 47.

### 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 regulation or non-regulation reserves. Both regulation and non-regulation reserves  
21 include both *inc* capacity or *dec* capacity. Power Rates Study Documentation, BP-24-FS-  
22 BPA-01A, Tables 9.3.1.3 and 9.3.1.5.

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-24-FS-BPA-06A, 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-24-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 \$1,063.8 million per year. Power Rates Study Documentation, BP-24-FS-BPA-  
2 01A, Table 9.3.1.7, line 24.

### 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 \$823.2 million for the rate  
8 period. *Id.*, line 7.

### 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 the  
16 Northwest Power and Conservation Council (NPCC) to help finance its Fish and Wildlife  
17 program (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 \$307.8 million per year for the rate period. *Id.*, line 12.

### 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 \$/MWh cost  
4 only, with no visibility into the capacity and energy cost components. In these situations, a  
5 ratio of maximum-output to maximum-output-plus-average-generation is used to classify  
6 the portion of the total cost that is attributable to capacity. For a flat annual block of power,  
7 this method attributes 50 percent of the cost to energy and the other 50 percent to  
8 capacity. This is because, for a flat block of power, the maximum generation and average  
9 generation are the same. For Clearwater Hatchery Generation, which is the only physical  
10 hydro resource that BPA currently pays for the output in a single dollars per megawatthour  
11 cost, this method attributes 39.5 percent to energy and 60.5 percent to capacity. The total  
12 rate period average of power purchase costs classified as capacity costs for purposes of  
13 calculating BPA's unit cost of capacity is \$2.9 million per year. Power Rates Study  
14 Documentation, BP-24-FS-BPA-01A, Table 9.3.1.7., line 18.

### 16 **Cost Adjustments**

17 Two cost adjustments are made to the total embedded costs, one for the 4(h)(10)(C) credit  
18 and another for Synchronous Condensing. The portion of the 4(h)(10)(C) credit that is  
19 associated with program costs is included because fish and wildlife program costs are  
20 included in the capacity cost calculation, and a portion of 4(h)(10)(C) credit is an offset to  
21 those costs. The portion of the 4(h)(10)(C) credit that is associated with the cost of  
22 balancing purchases is excluded because the cost of balancing purchases is classified as an  
23 energy cost. The portion of BPA's capacity costs that are allocated to Synchronous  
24 Condensing – the investments in plant modifications at the John Day and The Dalles  
25 projects that are necessary to provide Synchronous Condensing – are removed (\$217,000  
26 per year) to avoid double counting, since these capacity costs are associated with

1 Synchronous Condensing and are already assigned to Transmission through that  
2 methodology, as described in Section 9.3.2 of this Study. *Id.*, line 22. The portion of the  
3 4(h)(10)(C) credit associated with capacity and the removal of the costs associated with  
4 Synchronous Condensing totals an average of \$70.1 million per year for the rate period.  
5 *Id.*, line 23.

### 7 **Treatment of Conservation**

8 All costs associated with conservation are excluded from the calculation of the embedded  
9 capacity cost. This is because, although energy conservation provides both capacity and  
10 energy benefits, the amount of capacity provided from BPA's conservation investments is  
11 not readily available. Given this, both the costs of conservation and conservation's  
12 contribution to the system capability of the resources available to BPA are excluded.

#### 14 **9.3.1.2.2 The Capacity Available to BPA**

15 The capacity of all the resources available to BPA, excluding conservation (*see* Section  
16 9.3.1.2.1 above), is made up of (1) physical resources (regulated hydro, independent hydro,  
17 small hydro, and thermal); and (2) forecast or actual generation augmentation purchases.  
18 Non-hydro renewable generation, described in detail in the Power Loads and Resources  
19 Study, BP-24-FS-BPA-03, § 3.1.3, is excluded. Although these wind and solar resources  
20 produce energy, they are excluded from capacity because these forms of generation are  
21 variable. The capacity provided by physical resources and augmentation purchases are  
22 increased by the amount of capacity provided by Power Services to support Ancillary and  
23 Control Area Services. The sum of these two sources, as adjusted for the amount of  
24 capacity provided for Ancillary and Control Area Services, is equal to an annual average  
25 one-hour system capability (under monthly P10 water conditions) of 14,212 MW for the

1 rate period. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.8,  
2 line 10.

#### 3 4 **Capacity from Physical Resources**

5 BPA's primary source of capacity is from physical resources and is equal to 12,998 MW.

6 Physical resource capacity is established as described in the Power Loads and Resources  
7 Study, BP-24-FS-BPA-03, § 3.1.2. The 14-period one-hour capacity of each Federal  
8 resource type is averaged to create an annual average one-hour capacity under monthly  
9 P10 water conditions. These average annual one-hour capacities are then averaged across  
10 the two-year rate period, and reduced for transmission losses, to create rate period average  
11 one-hour capacities after losses. *See* Power Rates Study Documentation, BP-24-FS-BPA-  
12 01A, Table 9.3.1.6.

#### 13 14 **Capacity from Power Purchases**

15 BPA may also obtain additional capacity through forecast and actual power purchases.  
16 All forecast and actual power purchase amounts considered augmentation purchases are  
17 included in the total amount of capacity available to BPA. System augmentation is  
18 discussed in the Power Loads and Resources Study, BP-24-FS-BPA-03, § 4.2, and System  
19 augmentation amounts are presented in that Study in Table 2. Any power purchased to  
20 serve loads at a Tier 2 rate is also included. All augmentation purchases, including  
21 purchases made to serve loads at a Tier 2 rate, are assumed to be made on a flat annual  
22 basis. These flat augmentation purchases increase the amount of capacity available to the  
23 Federal system by an equal amount in all months. *See* Power Rates Study Documentation  
24 BP-24-FS-BPA-01A, Table 9.3.1.6, lines 23-24.

1 **Capacity Provided for Ancillary and Control Area Services**

2 The amount of capacity forecast to be provided by Power Services to support Ancillary and  
3 Control Area Services is equal to 1,214 MW. Power Rates Study Documentation, BP-24-FS-  
4 BPA-01A, Table 9.3.1.8, line 9. This amount is added to the capacity available to BPA from  
5 physical resources and power purchases because the capacity of the physical resources  
6 reflected in the Power Loads and Resources Study, BP-24-FS-BPA-03, § 3.1.2, has already  
7 been reduced for the balancing and operating capacity obligation.

8  
9 **9.3.1.2.3 Embedded Unit Cost Calculation**

10 The embedded unit cost of capacity is calculated by taking the costs attributable to capacity  
11 (see § 9.3.1.2.1) and dividing by the capacity of the resources available to BPA. The  
12 embedded unit cost of capacity is equal to \$6.24 per kilowatt (kW) per month. Power Rates  
13 Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.8, line 16.

14  
15 **9.3.1.3 Variable Cost Pricing Methodology**

16 **9.3.1.3.1 Introduction and Purpose**

17 When BPA holds capacity, it incurs variable costs due to efficiency losses. Efficiency losses  
18 impact the Federal system in regard to output in MWs, timing of energy generated, and  
19 revenues received. The Generation and Reserves Dispatch (GARD) Model is an R-based  
20 model designed to calculate the costs of the various forms of efficiency losses associated  
21 with ensuring that sufficient machine capability is ready and capable of responding to, and  
22 delivering, the balancing and operating reserve capacity. These efficiency costs are  
23 determined by measuring the difference between: (1) the costs of operating the Federal  
24 system at an optimal efficient level *without* holding capacity reserves; and (2) the cost of  
25 operating the Federal system at an optimal level *with* holding capacity reserves. The  
26 difference between those costs are generally referred to as variable costs.

1 The variable costs associated with providing a quantity of balancing reserve capacity are  
2 calculated in the GARD Model using inputs from the HYDSIM model, reserve requirement  
3 data, and Aurora<sup>®</sup> price forecasts. The purpose of the GARD Model is to calculate the  
4 variable costs incurred as a result of operating the Federal system with the necessary  
5 balancing reserve capacity to maintain reliability and for deploying the balancing reserve  
6 capacity to maintain load-resource balance within the BPA BAA. Load-resource balance is  
7 maintained by the automatic increase or decrease of generation in response to  
8 instantaneous changes in demand and/or power production. The ability to be ready and  
9 able to automatically increase generation is referred to as an *inc* reserve. Likewise, the  
10 ability to be ready and automatically decrease generation is referred to as a *dec* reserve.

11  
12 The GARD Model calculates the costs associated with standing ready to provide capacity  
13 reserves. These costs are referred to as 'Stand-ready' costs and are comprised of the  
14 following:

- 15 1. Energy shift associated with providing *dec* reserves
- 16 2. Energy shift associated with providing non-spinning *inc* reserves
- 17 3. Energy shift associated with providing spinning *inc* reserves
- 18 4. Efficiency changes associated with providing *dec* reserves
- 19 5. Efficiency changes associated with providing non-spinning *inc* reserves
- 20 6. Efficiency changes associated with providing spinning *inc* reserves
- 21 7. Spill costs associated with providing non-spinning *inc* reserves
- 22 8. Spill costs associated with providing spinning *inc*

23  
24 For each cost category, the GARD Model produces monthly cost and associated energy  
25 results for heavy load hours (HLH) and light load hours (LLH) by water year; the energy is  
26 denominated in megawatthour losses (positive losses are reflected as gains in the GARD



1 Model). The remainder of this Section 9.3.1.3 details the definition and calculation of each  
2 identified cost element.

3  
4 In considering the variable costs, the GARD Model seeks to efficiently commit and dispatch  
5 the units at projects armed for AGC response, generally referred to in this Study as  
6 “controller projects.” The goal is to meet each controller project’s generation request, meet  
7 the balancing reserve capacity obligation, and respond to a simulated balancing reserve  
8 capacity need. In the process of making controller projects capable of responding and then  
9 actually providing response, the efficiency of the generators changes.

10  
11 After calculating the impacts of carrying and deploying balancing reserve capacity, costs  
12 are grouped into three general categories: (1) spinning *inc* costs, (2) non-spinning *inc*  
13 costs, and (3) *dec* costs. From these three general groupings, the total cost is subdivided by  
14 the reserve service: (1) regulation balancing, (2) non-regulation balancing, and (3)  
15 operating reserves.

#### 16 17 **9.3.1.3.2 Pre-Processes and Inputs**

18 This section describes the preparation of the input data for the GARD Model.

#### 19 20 **Generation Request**

21 The primary inputs into the GARD Model are tables of controller project-specific generation  
22 values calculated by HYDSIM. See the Power Loads and Resources Study, BP-24-FS-BPA-  
23 03, for information on the HYDSIM model. These generation tables are used to determine  
24 the generation request, which determines the controller project’s unit commitment and  
25 dispatch. The generation request is the amount of HLH or LLH generation that a specific  
26 controller project is being asked to produce. The controller project’s unit commitment and

1 dispatch is the number, and/or combination, of online units required to meet the  
2 generation request and reserve obligation.

3  
4 Determining the specific HLH and LLH generation request begins with monthly energy  
5 amounts for each of the 30 historical water years from HYDSIM. Monthly energy amounts  
6 are taken for Grand Coulee (GCL), Chief Joseph (CHJ), John Day (JDA), and The Dalles (TDA).  
7 All but four of the 31 projects in the Federal system are AGC-equipped. However, GCL, CHJ,  
8 JDA, and TDA are the only projects analyzed because these four controller projects are  
9 most often armed by the hydro duty scheduler for AGC response. The 30 years of monthly  
10 energy amounts from HYDSIM for the four controller projects are taken as inputs into a  
11 pre-processing spreadsheet before being input into the GARD Model.

12  
13 The purpose of the pre-processing spreadsheet is to shape the HYDSIM energy into HLH  
14 and LLH generation amounts for each of the four projects. The shaping of energy into HLH  
15 and LLH generation quantities is a function of the historical relationship between average  
16 generation across all hours (average energy) and HLH generation for each of the controller  
17 projects, constrained by unit availability, 1 percent peak generation constraints, and  
18 minimum turbine flow constraints. Development of the functional relationships between  
19 average energy production and HLH generation relies on Supervisory Control and Data  
20 Acquisition (SCADA) data from January 1, 2002, through December 31, 2007. The 2002-  
21 2007 period balances the need for a robust data set with the desire for operations that are  
22 similar to current practice and bound by similar constraints. Additionally, there is little to  
23 no influence from wind generation in this period. After 2007, the relationship between  
24 average energy production and HLH generation is impacted by the amount of wind  
25 interconnected in the BPA BAA.

1 After the HLH and LLH generation are calculated for each controller project for each month  
2 of each historical water year based on the previously described function, the generation  
3 quantities are input into the GARD Model as the generation request. The generation  
4 request appears as a table of 12 months by 30 water years for HLH and LLH (a total of 720  
5 generation values). The generation request values are used by the GARD Model to  
6 determine the unit commitment and dispatch for each of the controller projects. That is,  
7 for each month of each water year for HLH and LLH, generation values are given to the  
8 GARD Model for each controller project. Given these generation values, the GARD Model  
9 will find the plant efficiency-maximizing unit commitment and dispatch. This process  
10 simulates the basepoint setting process in which the hydro duty scheduler submits  
11 requested generation amounts to each controller project and the controller project  
12 commits and dispatches its units in the most efficient manner possible.

13

14 An additional secondary input to the GARD Model, also derived from the pre-processing  
15 spreadsheet, is a matrix of the amount of pre-existing *dec* capability for each controller  
16 project by month and historical water year. Pre-existing *dec* capability is defined as the  
17 difference between the calculated LLH generation and the minimum generation for each of  
18 the respective controller projects. The purpose of this input is to avoid unnecessarily  
19 moving energy out of HLH and into LLH when providing *dec* capability.

20

## 21 **Reserves**

22 Reserve requirements are an input into the GARD Model and are classified as either  
23 Balancing Reserves or Operating Reserves. Balancing Reserves are further classified into  
24 either regulation or non-regulation, each of which have *inc* and *dec* quantities. Given these  
25 reserve classifications, the GARD Model determines the required amounts of spinning and

1 non-spinning reserve to meet *inc* obligations and the amount of generation required to  
2 meet *dec* obligations.

3  
4 The determination of the quantities of spinning reserve versus the quantities of non-  
5 spinning reserve is derived from NERC requirements as well as system operator judgment.  
6 NERC requires that at least 50 percent of the BAA Operating Reserve obligation be met  
7 with spinning capability responsive to AGC. NERC also requires that 100 percent of the  
8 BAA Regulation Balancing Reserves must be carried on units with spinning capability  
9 responsive to AGC, due to the fact that Regulating Reserve must respond on a moment-to-  
10 moment basis. In contrast, Non-regulation Balancing Reserves do not have NERC-defined  
11 criteria, and therefore it is assumed that at least 50 percent of the *inc* following reserve  
12 must be carried as a spinning obligation and up to 50 percent as a non-spinning obligation.

13  
14 The rationale for carrying at least 50 percent of the *inc* non-regulation requirement as  
15 spinning is to provide sufficient response over the first five minutes of movement while  
16 simultaneously providing enough time to synchronize non-spinning units and ramp the  
17 units through their suboptimal operation. Synchronization generally takes about three  
18 minutes, with the unit fully ramped over the next seven minutes. Should additional  
19 balancing reserve capacity be required to cover a growing imbalance, additional units are  
20 synchronized and ramped as the spinning portion of non-regulation reserve is consumed  
21 and the remaining non-regulation reserve capacity is deployed with non-spinning  
22 capability. By definition, all *dec* reserve capacity (the *dec* portion of the regulation and non-  
23 regulation) is spinning, because units must be generating (*e.g.*, with turbines spinning) in  
24 order to deploy *dec* reserve capacity.

1 **Controller Project Responses**

2 Controller project responses determine the relative balancing reserve capacity obligation  
3 for a given controller project as well as the relative reserve deployment quantity. As in  
4 actual operations, responses are input into the GARD Model as percentages, allocating the  
5 reserve capacity obligation among the controller projects. The response percentage  
6 prorates the reserve carrying and deployment across the selected controller projects. The  
7 response percentages are functions of water condition, time of year, and, ultimately,  
8 controller project flexibility.

9  
10 Controller project responses are input into the GARD Model by month and water year to  
11 account for the changing reserve capacity carrying capability as dictated by hydrologic  
12 conditions and unit availability. The expected response scheme for July through March is  
13 50 percent at GCL, 25 percent at CHJ, 15 percent at JDA, and 10 percent at TDA. The  
14 expected scheme for April through June is 60 percent at GCL, 30 percent at CHJ, 5 percent  
15 at JDA, and 5 percent at TDA. However, significant departures from the expected scheme  
16 can occur due to varying hydraulic conditions.

17  
18 **9.3.1.3.3 Stand-Ready Costs**

19 To meet the potential balancing reserve capacity requirements in any given hour, BPA's  
20 system is set up in advance so that the required balancing reserve capacity is available  
21 during all operating hours. Stand-ready costs are those variable costs associated with  
22 holding the required reserve capacity from the Federal system. Three specific costs are  
23 incurred when preparing the Federal system to stand ready to deploy balancing reserve  
24 capacity as needed: energy shift, efficiency loss, and spill losses.

## 1 **Stand-Ready Energy Shift**

2 The GARD Model's first step in determining the stand-ready impacts of carrying balancing  
3 reserve capacity is to calculate how much energy is shifted out of the HLH period and into  
4 the LLH period. This movement of energy is referred to as the "energy shift" (also referred  
5 to as Hydro-shift). If the current generation request does not allow sufficient *inc* or *dec*  
6 capability, energy shift will occur. If the input generation request results in adequate  
7 balancing reserve capacity, energy shifting is not necessary, and no cost is assigned.

8  
9 Energy may shift out of the HLH period to make *dec* capability available during the LLH  
10 period and/or to make sufficient non-spinning and/or spinning *inc* capability available  
11 during the HLH period. In the first instance, fuel normally used to meet peak generation  
12 needs is consumed during periods of lowest demand so that sufficient generation capability  
13 exists on the Federal system to fully deploy *dec* reserves without violating minimum  
14 generation requirements. Should additional *inc* capability be required after completely  
15 flattening generation across the HLH period, such as in high-flow scenarios, energy is  
16 shifted into the LLH period.

17  
18 The GARD Model measures and logs the amount of energy shifted in order to meet the  
19 reserve requirements while operating under several assumptions and system constraints.  
20 The model assumes that HLH energy market values are greater than LLH energy values.  
21 System constraints include minimum generation levels and installed unit availability in a  
22 given period. The same data set described in the Generation Request portion of  
23 Section 9.3.1.3.2 was used to develop the necessary functional relationships used by the  
24 GARD Model. As energy is moved from one blocking period to another for a given reserve  
25 obligation, the GARD Model tracks and records these movements. This results in tables of

1 energy shift by month, water year, and blocking period caused by making available the  
2 capability to provide *dec*, non-spinning *inc*, and spinning *inc* reserves.

3  
4 Energy shift is valued as the price differential between the period from which energy is  
5 taken and the period into which energy is moved. See Power Rates Study Documentation,  
6 BP-24-FS-BPA-01A, Tables 9.3.1.9-14 The cost of *inc* energy shift is included in the total  
7 variable cost that is included in rates. For FY 2024-2025, the total annual average energy  
8 shift is 294,441 MWh, worth \$31.4 million. Power Rates Study Documentation, BP-24-FS-  
9 BPA-01A, Table 9.3.1.13, line 4.

### 11 **Stand-Ready Efficiency Change**

12 For any given generation request, a controller project has a unit commitment and dispatch  
13 that maximizes controller project efficiency by minimizing the amount of water flow per  
14 megawatt generated. For each generation request and balancing reserve capacity  
15 requirement, the GARD Model seeks to commit and dispatch each of the controller projects  
16 most efficiently. The efficient dispatch is a function of the individual controller project's  
17 generation request, the controller project's response, the characteristics of a given  
18 controller project's unit families (groups of units having similar performance  
19 characteristics), the unit availability, the minimum amount of spinning balancing reserve  
20 capacity required, and the amount of non-spinning balancing reserve capacity.

21  
22 The GARD Model optimizes the unit dispatch by loading each online unit such that the  
23 marginal cost of each unit is identical and the requested generation and balancing reserve  
24 capacity is met. Dispatching units at equal marginal costs results in the model meeting the  
25 objective of minimizing total turbine outflow per unit of fuel (water in thousands of cubic  
26 feet per second).

1 Changes in plant efficiency are calculated by month and water year for the HLH and LLH  
2 periods. Efficiency changes are calculated where *dec* balancing reserve capacity and non-  
3 spinning and spinning *inc* balancing reserve capacity are being provided. In calculating the  
4 amount of efficiency loss, the GARD Model calculates the most efficient unit commitment  
5 and dispatch for a given generation request without a balancing reserve capacity  
6 requirement and compares this efficiency to the efficiency obtained while meeting both the  
7 generation request and the input balancing reserve capacity requirement. To the extent  
8 that a given generation request results in an efficient dispatch with sufficient capability, no  
9 efficiency changes are calculated. Conversely, to the extent that a given generation request  
10 results in a unit commitment and dispatch with insufficient capability, the unit  
11 commitment and dispatch must be altered so that the required minimum balancing reserve  
12 capacity is carried.

13  
14 Efficiency changes, unit commitment, and dispatch decisions are driven by the unit  
15 characteristics of each controller project. The unit characteristics are defined by  
16 polynomial functions relating unit generation for each controller project's individual unit  
17 families to unit water flow. The polynomial functions are derived from actual measured  
18 generator unit data obtained from the Corps and Reclamation. This results in 10 unit  
19 families across four controller projects: GCL has four families, CHJ has three, JDA has one,  
20 and TDA has two. In addition to determining controller project efficiency for a given level  
21 of generation, the efficiency curves determine the upper and lower bounds of unit level  
22 generation for JDA and TDA during the months of April through September. During this  
23 time period, the units at JDA and TDA must generate within 1 percent of peak efficiency  
24 pursuant to Fish Passage Plan requirements. This constraint is applicable both when  
25 standing ready to provide reserves and during the deployment of reserves.

26



1 The GARD Model explicitly tracks the efficiency effects and produces returning tables of  
2 efficiency impacts by month, water year, and blocking period due to making available the  
3 capability to provide *dec*, non-spinning *inc*, and spinning *inc* reserves.

4  
5 Efficiency changes are valued at the HLH price from the market price forecast for each  
6 month of the rate period. The HLH price is used because efficiency impacts – losses and  
7 gains in energy – are taken out of or put into the HLH period. The total average annual  
8 efficiency change for FY 2024-2025 is a gain of 19,192 MWh, which reduces the total  
9 variable costs by \$7.7 million. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
10 Table 9.3.1.13, line 8.

#### 11 12 **Stand-Ready Spill Losses**

13 Spill losses may occur given the combination of a large *inc* balancing reserve capacity  
14 obligation and high river flows. Under these conditions, the GARD Model will flatten the  
15 generation pattern across all hours. The flattened generation profile maximizes the  
16 combined *inc* and *dec* capability across all hours. Should the GARD Model still fail to carry  
17 sufficient *inc* capability, it will begin spilling to achieve the joint objective of meeting the *inc*  
18 reserve obligation and the controller project flow requirements.

19  
20 Spill losses are valued at the respective HLH or LLH price from the market price forecast  
21 for each month of the rate period. The total average annual spill loss for the FY 2024-2025  
22 period is 220,222 MWh, worth \$7.2 million. *Id.*, line 11.

#### 23 24 **9.3.1.3.4 Variable Cost of Reserves**

25 The end goal of determining the variable cost of reserve capacity is the ability to assign  
26 specific costs to specific types of balancing and operating reserve capacity. Placing the

1 output of the GARD Model into a post-processing spreadsheet containing market prices  
2 yields the cost of reserve capacity by type and, ultimately, by reserve service. The variable  
3 cost of balancing reserve capacity is apportioned proportional to *inc* and *dec* quantities  
4 while the cost of operating reserves is only apportioned to *inc* quantities because operating  
5 reserves are only provided as *inc* reserves. As discussed in the Reserves portion of  
6 Section 9.3.1.3.2, the type of reserve determines how the GARD Model carries the reserve  
7 (*i.e.*, as spinning or non-spinning), with the final result being cost. The cost of carrying  
8 reserve capacity is subtotaled into the following five reserve categories, as listed in  
9 Section 9.3.1.3.1: regulation *inc*, regulation *dec*, non-regulation *inc*, non-regulation *dec*, and  
10 the spinning portion of operating reserves.

11  
12 The variable cost of holding non-regulation balancing reserves are reduced, or offset, to  
13 account for potential revenues generated through BPA's EIM participation. The EIM makes  
14 it possible to market non-regulation balancing reserves, as well as additional surplus  
15 capacity, and recoup a portion of the variable costs incurred by holding non-regulation  
16 balancing reserves. Pursuant to the BP-24 Settlement Agreement, BPA will reduce the  
17 variable (GARD) costs associated with non-regulation balancing reserves by 95 percent.  
18 Fredrickson *et al.*, BP-24-FS-BPA-09, Appendix A, Attachment 3, § II.A.9. The total  
19 reduction in non-regulation balancing reserve variable costs is \$13.5 million. Power Rates  
20 Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.15, line 5.

21  
22 The aggregation of the GARD Model-calculated variable costs into the respective reserve  
23 service categories is shown in Power Rates Study Documentation, BP-24-FS-BPA-01A,  
24 Table 9.3.1.15. The total average annual loss for the FY 2024-2025 period is 533,856 MWh,  
25 valued at \$30.9 million. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table  
26 9.3.1.13, line 12. After accounting for the estimated cost reduction from the EIM, the total

1 annual average Federal system variable cost used for setting rates for FY 2024-2025 is  
2 \$17.4 million. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.15,  
3 line 6. This table also shows the variable costs for the regulation (*inc* and *dec*), non-  
4 regulation (*inc* and *dec*), and the spinning portion of operating reserves.  
5

#### 6 **9.3.1.4 Rate Design Cost Adjustment Methodology**

7 After embedded and variable costs have been calculated and before final reserve capacity  
8 rates are established, a rate design step is applied to incremental capacity reserves to  
9 reflect the relative opportunity costs associated with providing different types of capacity –  
10 fast and flexible capacity as compared to slower and less flexible capacity. The value delta  
11 is equal to the difference in costs between thermal generators designed for each type of  
12 reserve capacity type. The outcome of this benchmarking process illustrates that faster  
13 and more flexible capacity is more costly than slower and less flexible capacity. The  
14 process by which BPA applies the value delta to regulation and non-regulation *inc*  
15 balancing reserves and spinning and supplemental operating reserves is detailed in  
16 Section 9.3.1.5.1 below.  
17

#### 18 **9.3.1.4.1 Fast and Flexible vs. Slower and Less Flexible Incremental Benchmarking**

19 Measuring the cost differential between fast and flexible versus slower and less flexible  
20 reserves begins by selecting benchmarking generators that are appropriate for providing  
21 each type of *inc* service. The Wärtsilä 18V50SG reciprocating generator is selected to  
22 benchmark costs associated with providing fast and flexible reserve services and the  
23 General Electric 7HA.02 combustion turbine is selected for providing slower and less  
24 flexible services. The Wärtsilä reciprocating generator (RG) is used to benchmark  
25 regulation and spinning operating reserves due to its technical capability to provide fast  
26 and flexible reserve capacity. The 7HA.02 turbine, on the other hand, is a standard in

1 providing slower and less flexible capacity due to its fuel efficiency and lower long-term  
2 costs. The 7HA.02 turbine is used to benchmark non-regulation and supplemental  
3 operating reserves.

4  
5 Benchmarking is conducted by calculating the annual average expense to own, operate and  
6 maintain the Wärtsilä RG and the 7HA.02 combustion turbine (CT). A detailed description  
7 of how annual fixed costs associated with the Wärtsilä RG are calculated is available in  
8 Section 4.1.1.2.1 above and shown in Power Rates Study Documentation, BP-24-FS-  
9 BPA-01A, Table 4.1. The same process is applied to the 7HA.02 CT to determine the  
10 annual average expense to own, operate and maintain the generator. Power Rates Study  
11 Documentation, BP-24-FS-BPA-01A, Table 9.3.1.16. The annual average expense is divided  
12 by 12 to calculate the monthly average cost to operate each generator. The average  
13 \$/kW/month costs for the Wärtsilä RG and 7HA.02 CT are compared to derive the cost  
14 differential. This cost differential is used to create the value delta between the spinning  
15 and non-spinning *inc* reserve capacity.

16  
17 For FYs 2024-2025, the estimated average cost for the Wärtsilä RG is \$9.54/kW/month and  
18 for the 7HA.02 CT is \$5.82/kW/month. Power Rates Study Documentation, BP-24-FS-BPA-  
19 01A, Table 4.1, line 14 and Table 9.3.1.16, line 14. The value delta for FYs 2024-2025 is  
20 thus \$3.72/kW/month. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table  
21 9.3.1.16, line 25, column J.

### 22 23 **9.3.1.5 Capacity Cost Calculation**

#### 24 **9.3.1.5.1 Unit Cost by Reserve Type**

25 The variable costs allocated to *inc* balancing, *dec* balancing, and operating reserves are  
26 divided by their respective quantities of capacity to calculate a unit cost of the allocated

1 variable costs. As discussed above, the GARD Model only calculates costs associated with  
2 the spinning portion of the operating reserve requirement; however, those variable unit  
3 costs are allocated into a general operating reserve cost bucket due to the fact that they are  
4 differentiated in a later rate design step that is described below.

- 5 • For *inc* balancing the unit cost of allocated variable costs is \$0.48/kW/month.
- 6 • For regulation *dec* balancing the unit cost of allocated variable costs is  
7 \$0.99/kW/month.
- 8 • For non-regulation *dec* balancing the unit cost of allocated variable costs is  
9 \$0.05/kW/month.
- 10 • For operating reserves the unit cost of allocated variable costs is \$1.54/kW/month.

11  
12 The embedded unit cost of \$6.24/kW/month (Power Rates Study Documentation, BP-24-  
13 FS-BPA-01A, Table 9.3.1.17, line 2) is added to the unit cost of allocated variable costs for  
14 *inc* balancing and operating reserves. The unit cost for *dec* reserves has no embedded cost  
15 component. The total unit cost of allocated embedded and variable costs for each type of  
16 capacity is as follows:

- 17 • The total unit cost for *inc* balancing is \$6.72/kW/month (*id.*, lines 12, 14).
- 18 • The total unit cost for regulation *dec* balancing is \$0.99/kW/month (*id.*, line 13).
- 19 • The total unit cost for non-regulation *dec* balancing is \$0.05/kW/month (*id.*,  
20 line 15).
- 21 • The total unit cost for operating reserves is \$7.78/kW/month (*id.*, line 16).

22  
23 Once the total unit cost is determined, a rate design step is applied to create a price  
24 differential between regulation and non-regulation *inc* balancing reserves as well as  
25 between spinning and supplemental operating reserves to reflect the differing opportunity  
26 costs (i.e., the value delta as described above) associated with providing these capacity

1 types. The goal of this step is to establish a fixed price delta between unit costs of faster  
2 services and slower services without collecting more revenue than the amount of costs  
3 allocated to each service prior to applying the rate design step.

4  
5 The process of applying the rate design step begins with the total allocated costs  
6 (embedded and variable) of each service along with the total MW quantities forecasted for  
7 the two capacity types within each service (regulation and non-regulation for the balancing  
8 service and spinning and supplemental for the operating reserve service). The following  
9 set of two equations are then applied to calculate the cost of the two balancing reserves  
10 types (regulation and non-regulation):

11  
12 *Balancing inc Reserves*

$$13 \quad UC_R - UC_{NR} = VD$$

$$14 \quad UC_R(MW_R) + UC_{NR}(MW_{NR}) = TotalAllocatedCost_{Bal\_Inc}$$

15  
16 *Where:*

17  $UC_R$  refers to the unit cost for regulating *inc* reserves.

18  $UC_{NR}$  refers to the unit cost for non-regulating *inc* reserves.

19  $VD$  refers to the Value Delta (*i.e.*, the opportunity cost rate design goal), as described  
20 in Section 9.3.1.4.1 above, and is equal to \$3.72/kW/month.

21  $MW_R$  refers to the quantity of regulation *inc* reserves.

22  $MW_{NR}$  refers to the quantity of non-regulation *inc* reserves.

23  $TotalAllocatedCost_{Bal\_Inc}$  refers to the total costs allocated to *inc* balancing  
24 services.

1 The average annual regulation balancing *inc* reserves forecasted for the rate period is  
2 302,000 kWh and non-regulation balancing *inc* reserves are 418,000 kWh. Power Rates  
3 Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.18, lines 14, 16. The average annual  
4 amount of costs allocated to regulation and non-regulation balancing *inc* is \$57.5 million.  
5 *Id.*, lines 21, 23. Given this information, the regulation balancing *inc* service receives a  
6 value adjustment of +\$2.10/kW/month and non-regulation balancing *inc* service receives  
7 a value adjustment of -\$1.62/kW/month. Power Rates Study Documentation, BP-24-FS-  
8 BPA-01A, Table 9.3.1.17, lines 21-22. After the rate design step is applied, the unit cost for  
9 regulation *inc* balancing capacity is \$8.82/kW/month, and the unit cost for non-regulation  
10 *inc* balancing capacity \$5.10/kW/month. *Id.*, lines 27, 29.

11  
12 The following set of two equations are applied to calculate the cost of the two operating  
13 reserves types (spinning and supplemental):

14  
15 *Operating inc Reserves*

$$16 \quad UC_{Spin} - UC_{Sup} = VD$$

$$17 \quad UC_{Spin}(MW_{Spin}) + UC_{Sup}(MW_{Sup}) = TotalAllocatedCost_{OP}$$

18  
19 *Where:*

20  $UC_{Spin}$  refers to the unit cost for spinning operating reserves.

21  $UC_{Sup}$  refers to the unit cost for supplemental operating reserves.

22  $VD$  refers to the Value Delta (*i.e.*, the opportunity cost rate design goal) as described  
23 in Section 9.3.1.4.1 above and is equal to \$3.72/kW/month.

24  $MW_{Spin}$  refers to the quantity of operating spinning reserves.

25  $MW_{Sup}$  refers to the quantity of operating supplemental reserves.

1 *TotalAllocatedCost<sub>OP</sub>* refers to the total costs allocated to operating reserves  
2 service.

3  
4 The average annual operating reserves forecasted for this rate period are 474,000 kWh,  
5 half of which are spinning and half of which are supplemental. Power Rates Study  
6 Documentation, BP-24-FS-BPA-01A, Table 9.3.1.18, lines 10-11. The average annual  
7 amount of costs allocated to operating reserves is \$44,229,000. *Id.*, line 29. Given this  
8 information, spinning operating reserves receives a value adjustment of +\$1.86/kW/month  
9 and supplemental operating reserves an adjustment of -\$1.86/kW/month. Power Rates  
10 Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.17, lines 23-24. After the rate design  
11 step is applied, the unit cost is \$9.64/kW/month for spinning operating reserves capacity  
12 and \$5.92/kW/month for supplemental operating reserves capacity. *Id.*, lines 31-32.

#### 14 **9.3.1.5.2 Forecast of Revenue from Balancing Reserves**

15 The revenue from providing regulation reserves is forecast by applying the unit costs to the  
16 regulation reserve *inc* and *dec* quantity forecasts. The revenue forecast is an average  
17 annual amount of \$35.8 million. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
18 Table 9.3.1.18, lines 21-22.

19  
20 The revenue from providing non-regulation reserves is forecast by applying the unit costs  
21 to the non-regulation reserve *inc* and *dec* quantity forecasts. The revenue forecast is an  
22 average annual amount of \$25.9 million. *Id.*, lines 23-24.



1 **9.3.1.5.3 Forecast of Revenue from Operating Reserves**

2 The revenue from providing spinning operating reserves is forecast by applying the unit  
3 cost calculated above to the spinning operating reserves quantity forecast. The revenue  
4 forecast is an average annual amount of \$27.4 million. *Id.*, line 27.

5  
6 The revenue from providing non spinning operating reserve is forecast by applying the unit  
7 cost calculated above to the non spinning operating reserve quantity forecast. The revenue  
8 forecast is an average annual amount of \$16.8 million. *Id.*, line 28.

9  
10 **9.3.2 Synchronous Condensing**

11 **9.3.2.1 Introduction**

12 This section describes the method used to determine the amount of energy consumed by  
13 those FCRPS hydro generators that operate as synchronous condensers, and the  
14 determination of the cost of that energy that is allocated to BPA Transmission Services. It  
15 also describes the costs allocated to Transmission Services associated with the investment  
16 in plant modifications necessary to provide synchronous condensing at the John Day and  
17 The Dalles projects. Synchronous condensing costs allocated to Transmission Services are  
18 recovered through transmission rates and passed to BPA Power Services as an  
19 interbusiness-line transfer.

20  
21 **9.3.2.2 Description of Synchronous Condensers**

22 A synchronous condenser is essentially a motor with a control system that enables the unit  
23 to regulate voltage. These machines dynamically absorb or supply reactive power as  
24 necessary to maintain voltage as needed by the transmission system. Some FCRPS  
25 generators operate in synchronous condenser or “condense” mode for voltage control and  
26 for other purposes (*e.g.*, to accommodate operational constraints associated with taking a  
27 unit offline). A generator operating in condense mode provides the same voltage control

1 function as the unit does when generating real power. As with any motor, a unit operating  
2 in condense mode consumes real energy. Generators operating in condense mode in the  
3 FCRPS consume energy supplied by other units in the FCRPS.

### 4 **9.3.2.3 Synchronous Condenser Costs**

5 Synchronous condensing costs include the cost of (1) investment in plant modification at  
6 John Day and The Dalles projects necessary to provide synchronous condensing, and  
7 (2) energy consumed by FCRPS generators while operating in condense mode for voltage  
8 control.  
9

10  
11 The investments in plant modifications at the John Day and The Dalles projects result in an  
12 average cost of \$217,000 per year. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
13 Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-24-FS-BPA-  
14 02A, Table 2F. These costs are the annual capital-related costs in the power revenue  
15 requirement associated with the investment that Power Services made in the plants at the  
16 request of Transmission Services to enable synchronous condense capability.

17 For the costs associated with the energy used in condense mode operations, the amount of  
18 forecast energy is priced at an average annual market price. The methodology to  
19 determine the amount and cost of energy consumption is described below.  
20

### 21 **9.3.2.4 General Methodology to Determine Energy Consumption**

22 For the FY 2024-2025 rate period, the FCRPS generators capable of operating in condense  
23 mode are identified, and the number of hours that the generators would operate in  
24 condense mode for voltage control is forecast. The forecast is derived from historical  
25 synchronous condenser operations, based on an average of the following three years of  
26 data, which are fiscal years 2018, 2018, and 2019. Due to the short timeline of the

1 settlement for BP-24, obtaining more recent data was not possible; furthermore  
2 condensing hours of the units vary little from rate period to rate period, especially with  
3 respect to overall costs. The average number of hours is multiplied by the fixed hourly  
4 energy consumption for the generators to determine the amount of energy consumed. The  
5 fixed hourly energy consumption is the motoring power consumption of the specific  
6 generator units when they are operated in condense mode. *See Power Rates Study*  
7 *Documentation, BP-24-FS-BPA-01A, Table 9.3.2.1.* Finally, the market price forecast is  
8 applied to the amount of energy consumed to calculate the cost of synchronous condensing.  
9 The methodology for assigning historical synchronous condenser operations to the voltage  
10 control function and calculating the associated energy use for each of the FCRPS projects  
11 capable of operating in condense mode is described below.

12

#### 13 **9.3.2.4.1 Grand Coulee Project**

14 Six generators (Units 19-24) at the Grand Coulee project are capable of operating as  
15 synchronous condensers, although only three are typically operated in condense mode.  
16 The Study forecasts the number of hours that the Grand Coulee units will operate in  
17 condense mode based on historical condenser operations for the three-year historical  
18 period. The transmission system typically needs additional voltage control from the Grand  
19 Coulee project during nighttime hours (generally hours 20:00 to 06:00), when the lightly  
20 loaded transmission system results in excess reactive power and causes excess voltage on  
21 the system. Historical reactive demand and unit operations are examined, and units  
22 operated in condense mode are allocated to either Transmission Services or Power  
23 Services, based on the reactive demand of the transmission system, the reactive capability  
24 of the units, the number of units on-line producing real power, and operation of the shunt  
25 reactor (which absorbs reactive power and reduces voltage). The method for assigning

1 condensing units to the voltage control function and developing the forecast is described  
2 below.

3  
4 For the forecast, BPA first determines the total measured reactive demand that the  
5 transmission system placed on the six units during the nighttime hours. This measured  
6 reactive demand is based on archived reactive meter readings for the historical three-year  
7 period. The total measured reactive demand represents the total reactive support (*e.g.*,  
8 megavolt amperes reactive) provided by all six units, regardless of whether the units are  
9 condensing or generating real power. Recall that units operating in generation mode also  
10 provide reactive support in addition to real power. For each hour, the total measured  
11 reactive demand is compared to the reactive capability of the units online generating real  
12 power plus, if not operating, the reactive capability of the shunt reactor. If the reactive  
13 capability of online units and the shunt reactor is less than the total measured reactive  
14 demand for the hour, one or more units operating in condense mode are allocated to  
15 voltage control for that hour. If a condensing unit is allocated to voltage control for a single  
16 nighttime hour, the condensing operation of that unit is allocated to voltage control for the  
17 entire nighttime period to reflect the fact that, in practice, a unit would not be started and  
18 stopped on an hourly basis. Condensing units are allocated to voltage control in whole  
19 increments until the total measured reactive demand is met or exceeded. The number of  
20 condensing hours for the three-year historical period is averaged, and energy consumption  
21 is determined by multiplying the average annual condensing hours by the fixed hourly  
22 energy consumption of the generators. The forecast of total energy consumed by the Grand  
23 Coulee generators operating in synchronous condense mode for voltage control is  
24 13,024 MWh/yr. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.2.1,  
25 line 4.

1 **9.3.2.4.2 John Day, The Dalles, and Dworshak Projects**

2 The John Day project has four generators (Units 11-14), The Dalles has six generators  
3 (Units 15-20), and the Dworshak project has three generators (Units 1-3) capable of  
4 operating as synchronous condensers. These three projects condense only when requested  
5 by Transmission Services, so all hours in condense mode are assigned to voltage control.  
6 The number of condensing hours for the three-year historical period is averaged, and  
7 energy consumption is calculated by multiplying the average annual condensing unit hours  
8 by the fixed hourly energy consumption of the applicable hydro units. The forecast of total  
9 energy consumed by the generators operating in condense mode for voltage control is  
10 12,028 MWh/yr for John Day and The Dalles (*id.*, line 3), and 221 MWh for the Dworshak  
11 project (*id.*, lines 5-6).

12  
13 **9.3.2.4.3 Palisades Project**

14 The Palisades project has four generators (Units 1-4) that are capable of synchronous  
15 condensing. Units are operated in condense mode pursuant to standing instructions from  
16 Transmission Services based on operational studies, so all hours in condense mode are  
17 assigned to voltage control. The number of condensing hours for the three-year historical  
18 period is averaged. Energy consumption is determined by multiplying the average annual  
19 condensing unit hours by the fixed hourly energy consumption of the project. The forecast  
20 of energy consumption by the Palisades generators operating in condense mode for voltage  
21 control is 1,854 MWh/yr. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table  
22 9.3.2.1, line 7.

23  
24 **9.3.2.4.4 Willamette River Projects**

25 The Willamette River projects have seven generators capable of condensing, which include  
26 units in the Detroit project (Units 1-2), the Green Peter project (Units 1-2), and the Lookout

1 Point project (Units 1-3). Historically these units have been operated at times in condense  
2 mode. However, BPA studies indicate that condensing is not required from these projects  
3 for voltage support except under rare conditions. Therefore, the energy for condensing  
4 operation for voltage control is forecast to be zero for the Willamette River projects. *Id.*,  
5 lines 8-10.

#### 7 **9.3.2.4.5 Hungry Horse Project**

8 The Hungry Horse project has four generators (Units 1-4) capable of condensing. Although  
9 capable of condensing, Hungry Horse was not requested to operate in condense mode  
10 during the three-year historical period. Therefore, the energy consumption for the Hungry  
11 Horse generators is forecast to be zero. *Id.*, line 11.

#### 13 **9.3.2.5 Summary – Costs Assigned to Transmission Services**

14 Synchronous condensing costs assigned to Transmission Services are the investments in  
15 plant modifications and the energy consumed for condensing operation. As stated above,  
16 the investments in plant modifications at the John Day and The Dalles projects result in an  
17 average cost of \$217,000 per year. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
18 Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-24-FS-BPA-  
19 02A, Table 2F.

21 The energy forecast to be consumed by FCRPS generators operating in condense mode  
22 totals 27,127 MWh. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.2.1,  
23 line 13. The energy consumed for condensing operation is priced at the market price  
24 forecast. *See* Power Market Price Study and Documentation, BP-24-FS-BPA-04, § 2.4.  
25 Applying the market price forecast of \$39.62 per MWh to the energy consumed results in a  
26 total cost of \$1,074,757 per year. Power Rates Study Documentation, BP-24-FS-BPA-01A,

1 Table 9.3.2.1, line 13. This amount is made up of \$476,530 per year in energy costs for the  
2 Southern Intertie, and \$598,228 associated with energy costs for voltage control for the  
3 Network. *Id.*, lines 3, 12. Total synchronous condensing cost allocated to Transmission  
4 Services (TS), then, is the sum of the \$217,000 per year in plant investments for the  
5 Southern Intertie and the total cost of energy consumed of \$1,074,757, which equals  
6 \$1,291,757 per year. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.2.3,  
7 lines 1, 5.

### 9 **9.3.3 Generation Dropping**

#### 10 **9.3.3.1 Introduction**

11 This section describes the method for allocating costs of Generation Dropping, including  
12 identifying the assumptions used in the methodology and establishing the generation input  
13 cost allocation that is applied to determine the annual revenue forecast for generation  
14 inputs.

#### 16 **9.3.3.2 Generation Dropping Requirement**

17 The BPA transmission system is interconnected with several other transmission systems.  
18 To maximize the transmission capacity of these interconnections while maintaining  
19 reliability standards, Remedial Action Schemes (RAS) are developed for the transmission  
20 grids. These schemes automatically make changes to the system when a contingency  
21 occurs to maintain loadings and voltages within acceptable levels. Under one of these  
22 schemes, Transmission Services requests that Power Services instantaneously drop  
23 (disconnect from the system) large increments of generation (at least 600 MW). To satisfy  
24 this requirement, the generation must be dropped virtually instantaneously from a certain  
25 region of the transmission grid. Under the current configuration of the transmission grid  
26 and the individual generating plant controls, Power Services can most expeditiously

1 provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric  
2 units (each of which exceeds 600 MW capacity).

### 3 4 **9.3.3.3 General Methodology**

5 The methodology for calculating the cost of Generation Dropping starts with two factors:  
6 the impact to the equipment involved and the lost revenue associated with that impact.

7 These factors are applied to a single generating unit at the Grand Coulee Third Powerhouse  
8 to arrive at an estimate of a single generation drop. This number is then multiplied by the  
9 estimated average drops per year to arrive at an estimate of the cost of Generation

10 Dropping for each year of the rate period. Generation Dropping causes additional wear and  
11 tear on equipment that will decrease the life and increase the maintenance of the unit. For  
12 each major component that is affected by this service. Power Rates Study Documentation,  
13 BP-24-FS-BPA-01A, Table 9.3.3.1 shows the cost associated with incremental equipment  
14 deterioration, replacement, and overhaul, and the cost associated with incremental routine  
15 operation and maintenance.

16  
17 Historical data for the Grand Coulee Third Powerhouse generating units and statistical data  
18 for other hydroelectric units provide capital cost, operation and maintenance costs, and  
19 frequency of operation information for the Generation Dropping analysis. Stresses on the  
20 equipment from Generation Dropping versus stresses during normal operation are  
21 compared. Through the application of this data, the capital and operation and maintenance  
22 costs for Generation Dropping are developed. The impacts are converted into a percentage  
23 change in equipment life and percentage increase in operations and maintenance for each  
24 operation.



1 **9.3.3.4 Generation Dropping Cost**

2 **9.3.3.4.1 Incremental Equipment Deterioration, Replacement, or Overhaul Costs**

3 One effect of additional deterioration because of Generation Dropping is a reduced period  
4 of time between major maintenance activities, such as major overhauls or replacements.

5 For purposes of this analysis, a “major overhaul” is defined as a maintenance activity for  
6 which at least partial disassembly of the affected equipment is required. The analysis  
7 focuses on evaluating the costs of additional, short-term deterioration of specific  
8 components or items for which statistical data are readily available. The costs of a major  
9 overhaul are derived from estimates or similar work performed in the past.

10 The percentage life reductions are determined using industry standards or actual project  
11 records. *See Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.3.1,*  
12 *column B.* For example, turbine overhaul is a major maintenance effort that will increase in  
13 frequency as a result of Generation Dropping.

14  
15 Power Services previously contracted with Harza Engineering Company to work with  
16 Reclamation and the Corps (which operate and maintain the FCRPS projects) to evaluate  
17 the costs of providing Generation Dropping. The evaluation estimated the cost incurred by  
18 a typical Reclamation or Corps generating unit. These cost estimates are applied to a  
19 generating unit at the Grand Coulee Third Powerhouse. The costs in the original  
20 engineering study are updated using the Handy-Whitman Index to reflect price escalation  
21 of equipment and labor costs.

22  
23 The Handy-Whitman Index multiplier is applied to the equipment costs in the study  
24 performed by Harza Engineering Company. The annual Incremental Equipment  
25 Deterioration, Replacement, and Overhaul Cost per drop for FY 2024-2025 is calculated by

1 multiplying the percentage of Life Reduction per drop by the cost of a Major Overhaul. *Id.*,  
2 column D, line 6.

#### 3 4 **9.3.3.4.2 Incremental Routine Operation and Maintenance Costs**

5 In addition to more frequent major overhauls, increases in routine operations and  
6 maintenance costs are expected due to the additional deterioration caused by Generation  
7 Dropping. The Incremental Routine Operations and Maintenance (O&M) Cost per drop is  
8 calculated using the Percentage Increase O&M Per Drop and expected annual operations  
9 and maintenance costs per major piece of equipment. The percentage increase in O&M  
10 costs is assumed to be equivalent to the percentage life reductions used to determine the  
11 incremental deterioration, replacement, or overhaul costs (*e.g.*, a 0.1 percent reduction in  
12 life per drop will result in a 0.1 percent increase in annual O&M costs). Annual O&M costs  
13 are increased by an inflation factor of 2.44 percent for FY 2024-2025. The annual  
14 Incremental Routine O&M Cost per Drop for FY 2024-2025 is calculated by multiplying the  
15 Percentage Increase O&M Per Drop by the Annual O&M Cost. *See id.*, column G, line 6. It is  
16 assumed that these outages are longer than scheduled or unpredictable outages, and  
17 cannot be scheduled to avoid a loss in total project generation.

#### 18 19 **9.3.3.4.3 Incremental Lost Revenue in the Event of Replacement or Overhaul**

20 The revenue lost during outages for the overhaul or replacement of equipment is  
21 significant for the large generating units with a capacity exceeding 600 MW. Lost revenues  
22 are calculated based on the forecast market price averaged over the rate period, FY 2024-  
23 2025.

24  
25 The Downtime Cost is calculated by multiplying the average monthly generation loss for a  
26 Unit 22, 23, or 24 outage by the assumed months of downtime for each piece of equipment

1 by the market price forecast. *See* Power Market Price Study and Documentation, BP-24-FS-  
2 BPA-04, § 2.4. The annual Cost per Drop for FY 2024-2025 is calculated by multiplying the  
3 Probability of Failure by the Down Time Cost. Power Rates Study Documentation, BP-24-  
4 FS-BPA-01A, Table 9.3.3.1, column K, line 6.

### 6 **9.3.3.5 Costs to be Allocated to Transmission Services**

7 The factors described above are analyzed for their application on a single generating unit at  
8 the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall  
9 cost associated with each generation drop. From these analyses, the total cost associated  
10 with a single generator drop of one of the Grand Coulee Third Powerhouse Units is  
11 calculated to be \$502,442. *Id.*, column L, line 6.

12 Historically, large generating units at Grand Coulee have been dropped 30 times over the  
13 last 26 years (1996 through 2022). Therefore, the average of approximately 1.2 drops per  
14 year is used as the Generation Dropping estimate.

15  
16 Multiplying the 1.2 drops per year by the cost of a single drop (\$502,442), the forecast  
17 annual cost is \$552,686. *Id.*, column D, line 7. This cost is assigned to Transmission  
18 Services for recovery in transmission rates. The rate period annual average cost for  
19 Generation Dropping is a revenue credit to the power rates. *See* Power Rates Study  
20 Documentation, BP-24-FS-BPA-01A, Table 9.3.1.1 line 10.

## 22 **9.3.4 Redispatch**

### 23 **9.3.4.1 Introduction**

24 Under the Tariff and the Redispatch and Curtailment Business Practice, Transmission  
25 Services can initiate redispatch as part of congestion management efforts. Generally,

1 redispatch results in actions that can effectively relieve a transmission constraint that may  
2 impair the reliability of BPA's transmission system and maintains service to loads.

3  
4 The Business Practice provides three types of redispatch that Transmission Services can  
5 request from Power Services to relieve congestion: Discretionary Redispatch, Network  
6 Transmission (NT) Redispatch, and Emergency Redispatch. Additionally, the Business  
7 Practice provides Power Services the ability to purchase transmission to ensure delivery to  
8 load, such as in the form of redispatch for stranded Load. Power Services may provide  
9 redispatch through *incs* and *decs* of Federal generation, through purchases and/or sales of  
10 energy, or through transmission purchases. The purposes of each of these types of  
11 redispatch are discussed further below. The price of redispatch is calculated based on one  
12 of two sources, depending on how the redispatch is provided: (1) for redispatch provided  
13 from Federal generation, market prices for incrementing and decrementing Federal  
14 generation at the time the redispatch is provided; or (2) for redispatch provided by  
15 purchases and/or sales of energy or purchases of transmission, the actual cost to Power  
16 Services of purchasing and/or selling power or purchasing transmission.

17  
18 This Study forecasts the cost of redispatch that will be transferred as revenue to Power  
19 Services from Transmission Services for the provision of redispatch during the FY 2024-  
20 2025 rate period. The forecast is based on actual redispatch costs from October 2019 to  
21 August 2022, the most recent periods for which BPA has actual data that separates  
22 transmission purchases due to redispatch for stranded load from transmission purchases  
23 for NT Redispatch.

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 \$16,033 in FY 2019, and \$0 in FY 2020, FY 2021, and  
7 FY 2022 (through August), averaging \$4,090. Power Rates Study Documentation, BP-24-  
8 FS-BPA-01A, Table 9.3.4.1, column B provides the actual annual Discretionary Redispatch  
9 details for October 2019 to August 2022. For FY 2024 and FY 2025, Transmission Services  
10 forecasts Discretionary Redispatch of \$4,090 per year.

11  
12 **9.3.4.3 Network Integration Redispatch**

13 Under the Redispatch and Curtailment Business Practice, Transmission Services requests  
14 Network Integration (NT) Redispatch from Power Services to maintain firm NT schedules.  
15 NT Redispatch can be requested only after all non-firm Point-to-Point and secondary NT  
16 schedules are curtailed in a sequence consistent with NERC curtailment priority. Power  
17 Services must provide NT Redispatch when requested by Transmission Services to the  
18 extent that it can do so without violating non-power constraints.

19  
20 NT Redispatch totaled \$34,977 in FY 2019, \$262,326 in FY 2020, \$87,437 in FY 2021, and  
21 \$165,929 in FY 2022 (through August), averaging \$140,476. *Id.*, columns C-D. Of this total  
22 amount from 2019 through August 2022, only \$9,100 was associated with Power Services  
23 providing NT Redispatch through the redispatch of Federal generation or through power  
24 purchases or sales over this time period. The rest (\$541,569 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-24-FS-BPA-01A, Table 9.3.4.1 provides the actual annual  
2 NT Redispatch cost for FY 2019 through FY 2022 (through August).

3  
4 The NT Redispatch forecast for FY 2024-2025 is \$140,477 per year. This is a decrease from  
5 previous years' forecasts and is based on the change in granularity to separate  
6 transmission purchases due to redispatch for stranded load from transmission purchases  
7 for NT Redispatch.

#### 8 9 **9.3.4.4 Emergency Redispatch**

10 Under the Redispatch and Curtailment Business Practice, Transmission Services may  
11 request Emergency Redispatch from Power Services to minimize the risk and/or scope of  
12 a transmission system reliability condition. Power Services must provide Emergency  
13 Redispatch when requested.

14  
15 Emergency Redispatch for FY 2019, FY 2020, FY 2021, and FY 2022 (through August)  
16 totaled \$0. The average from FY 2019 to FY 2022 (through August) was \$0. *See Power*  
17 *Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.4.1, column E.*

18  
19 Because Emergency Redispatch is a rare event, Emergency Redispatch is forecast to be  
20 \$0 for FY 2024-2025. *Id.*

#### 21 22 **9.3.4.5 Redispatch for Stranded Load**

23 Under the Redispatch and Curtailment Business Practice, Power Services may purchase  
24 transmission to ensure delivery to load. Specifically, BPA serves certain load that, in cases  
25 of planned outages, "strand" that load from being electrically connected to BPA and must  
26 be served through third-party transmission service. In these situations Power Services

1 purchases the third-party transmission service to ensure delivery to BPA's load is not  
2 interrupted. These redispatch for stranded load costs are then reimbursed by  
3 Transmission Services.

4  
5 Redispatch for stranded load totaled \$251, 557 in FY 2019, \$71,779 in FY 2020, \$208,361  
6 in FY 2021, and \$203,618 in FY 2022 (through August), averaging \$187,580. The  
7 redispatch for stranded load forecast for FY 2024-2025 is \$187,580 per year. Power Rates  
8 Study Documentation, BP-24-FS-BPA-01A, Table 9.3.4.1, column F.

#### 9 10 **9.3.4.6 Revenue Forecast for Redispatch Service**

11 Based on the analysis above, total revenues of \$332,147 per year is forecast for FY 2024-  
12 2025 for Redispatch services provided by Power Services to Transmission Services. *Id.*,  
13 line 7.

### 14 15 **9.3.5 Station Service**

#### 16 **9.3.5.1 Introduction**

17 Station service refers to real power that Transmission Services takes directly off the BPA  
18 power system for use at substations and other locations, such as facilities located on BPA's  
19 Ross Complex and Big Eddy/Celilo Complex. For purposes of this Study, station service  
20 does not include power that BPA purchases from another utility or that is supplied by  
21 another utility for station service purposes. Because there are locations on the system  
22 where BPA does not have meters to measure station service use, the amount of energy use  
23 at BPA substations and other facilities is estimated. The annual average forecast market  
24 price from the Power Market Price Study, BP-24-FS-BPA-04, § 2.4, is applied to the  
25 estimated annual energy use adjusted for transmission losses to yield the annual costs that  
26 are allocated to Transmission Services for station service energy use. This section

1 describes the station service energy use and the procedure used to determine the costs that  
2 are allocated to Transmission Services for station service energy use.

#### 3 4 **9.3.5.2 Overview of Methodology**

5 The station service costing methodology consists of the following steps: First, a historical  
6 monthly average station service energy use was determined based on measured load data  
7 for a sample of BPA's substations based on size (large, medium, and small). Second, an  
8 average load factor of 9.45 percent was derived based on the ratio of installed station  
9 service transformation and energy use for those substations. Third, that average load  
10 factor of 9.45 percent is then applied to the total amount of installed transformation,  
11 measured in kilovolt amperes (kVA), at all BPA substations served directly by the BPA  
12 power system to determine a total usage. Fourth, the station service energy use for all  
13 facilities other than the Ross and Big Eddy/Celilo complexes is estimated by applying the  
14 average load factor to the total installed station service transformer capacity. This energy  
15 use is then added to the historical use for the Ross and Big Eddy/Celilo complexes to  
16 estimate total average monthly energy use. The monthly amount is multiplied by 12 to  
17 yield an annual average estimated total energy use for all substations, which is then  
18 adjusted for transmission losses by applying the BPA network loss factor, 2.04 percent.  
19 The annual average forecast market price from the Power Market Price Study, BP-24-FS-  
20 BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission  
21 losses to yield the annual costs that are allocated to Transmission Services for station  
22 service energy use.

#### 23 24 **9.3.5.3 Assessment of Installed Transformation**

25 This methodology begins by identifying the amount of installed transformation for all BPA  
26 substations. Installed transformation transforms power to a lower voltage to supply power



1 to the buildings and equipment at the substations. The total installed transformation is  
2 46,744 kVA. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.5.2, line 6.  
3 Of this amount, the total amount of installed transformation at BPA substations for which  
4 load data exists is 15,456 kVA. Power Rates Study Documentation, BP-24-FS-BPA-01A,  
5 Table 9.3.5.1, line 41.

#### 6 7 **9.3.5.4 Assessment of Station Service Energy Use**

8 The historical average monthly use for the Ross Complex is 1,749,300 kWh, and for Big  
9 Eddy/Celilo Complex is 1,822,937 kWh, for a total of 3,572,237 kWh. Power Rates Study  
10 Documentation, BP-24-FS-BPA-01A, Table 9.3.5.2, lines 4-5.

11  
12 The total historical average monthly use for other BPA locations for which load data exists  
13 is 1,066,446 kWh. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.5.1,  
14 line 41. Because not all use is metered, the total average monthly use for BPA substations  
15 is estimated based on the historical average monthly use multiplied by the average load  
16 factor. Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.5.2, lines 1-3.

#### 17 18 **9.3.5.5 Calculation of Average Load Factor**

19 The average monthly load factor is calculated by dividing the total historical monthly use  
20 for BPA substations for which load data is available by the total installed station service  
21 transformation for these BPA substations. This yields an average 9.45 percent load factor.  
22 Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.5.1, line 41.

#### 23 24 **9.3.5.6 Calculating the Total Station Service Average Use**

25 The total installed transformation is multiplied by the average calculated load factor to  
26 yield the calculated historical average monthly use for all facilities other than the Ross and

1 Big Eddy/Celilo complexes. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A,  
2 Table 9.3.5.2, lines 1-3. The historical station service energy use for the Ross Complex and  
3 the Big Eddy/Celilo Complex is then added to the calculated amount of energy use at all  
4 other BPA substations. *Id.*, lines 4-5. The total quantity of station service average use that  
5 Power Services supplies directly to BPA substations and other facilities is then adjusted for  
6 transmission losses by multiplying the average use by the BPA Transmission Network loss  
7 factor of 2.04 percent pursuant to Schedule 11 of BPA's Tariff. The adjusted quantity of  
8 station service average use supplied to BPA substations and other facilities after adding in  
9 the network losses is estimated to be 83,235 MWh per year. *Id.*, line 6.

#### 11 **9.3.5.7 Determining Costs to Allocate to Station Service**

12 The annual average forecast market price (*see* Power Market Price Study, BP-24-FS-BPA-  
13 04, § 2.4) applied to the estimated annual quantity of station service energy use, including  
14 network losses, yields the energy costs per year to be allocated to Station Service. The  
15 capacity rate for Real Power Losses (Section 4.4.2) applied to the estimated quantity of  
16 network losses, yields the capacity costs associated with network losses. The sum of the  
17 energy costs and the capacity costs associated with Real Power Losses equals the total  
18 costs to allocate to station service. This rate period annual average cost is \$3.307 million.  
19 Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.5.2, line 6.

#### 21 **9.3.5.8 Impact on Power Rates and Transmission Rates**

22 The rate period annual average cost for station service is a revenue credit to the power  
23 rates. *See* Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.3.1.1, line 13.

1 **9.4 Revenue from Treasury Credits**

2 Revenues are also forecast from two kinds of Treasury credits, or deductions, made from  
3 BPA's annual Treasury payment. These credits represent a partial reimbursement by the  
4 Treasury for expenses incurred by BPA throughout the year.

5  
6 **9.4.1 Section 4(h)(10)(C) Credits**

7 BPA pays all the costs relating to the obligations of Northwest Power Act  
8 Section 4(h)(10)(C) regarding protecting, enhancing, and mitigating fish and wildlife in the  
9 region. 16 U.S.C. § 839b(h)(10)(C). BPA is reimbursed by the U.S. Treasury for  
10 22.3 percent of the replacement power purchases BPA is expected to make due to fish  
11 mitigation, as well as an equal percentage of program and capital expenses related to the  
12 fish and wildlife programs. The 22.3 percent represents the non-power portion of the total  
13 FCRPS costs, which is the responsibility of taxpayers rather than BPA ratepayers. This  
14 Treasury credit is treated as Power Services revenue.

15  
16 Expenses relating to fish and wildlife programs are discussed in the Power Revenue  
17 Requirement Study, BP-24-FS-BPA-02, Section 1.2.1.4. The methodology for estimating the  
18 replacement power purchases resulting from changes in hydro system operations to  
19 benefit fish and wildlife is described in the Power Loads and Resources Study, BP-24-FS-  
20 BPA-03, Section 3.3.1. The cost of the increased purchases is estimated using RevSim and  
21 the market price forecast and is included in the Power and Transmission Risk Study,  
22 BP-24-FS-BPA-05, Section 4.1.1.1.5.6, and the Power and Transmission Risk Study  
23 Documentation, BP-24-FS-BPA-05A, Table 13. Forecast 4(h)(10)(C) credits are listed in  
24 Table 4 of this Study, line 23, and Power Rates Study Documentation, BP-24-FS-BPA-01A,  
25 Table 9.2, line 48.

1 **9.4.2 Colville Settlement Credits**

2 The Colville Settlement Agreement obligates BPA to make annual payments to the Colville  
3 Tribes. BPA receives annual credits from the U.S. Treasury against payments due the  
4 Treasury to defray a portion of the costs of making payments to the Colville Tribes. The  
5 Treasury credit for the Colville Settlement in FY 2024 and FY 2025 is set by legislation at  
6 \$4.6 million per year. *See* Confederated Tribes of the Colville Reservation Grand Coulee  
7 Settlement Act, Pub. L. No. 103-436, 108 Stat. 4577 (Nov. 2, 1994). The credit is shown on  
8 Table 4 of this Study, line 24, and Power Rates Study Documentation, BP-24-FS-BPA-01A,  
9 Table 9.2, line 49.

10  
11 **9.5 Power Purchase Expense Forecast**

12 Power Services forecasts three types of power purchase expenses: Augmentation  
13 Purchases, Balancing Purchases, and Other Power Purchases. Although most expenses,  
14 including some power purchase expenses, such as long-term generating resources, are  
15 forecast in the Power Revenue Requirement Study, the power purchase expenses described  
16 here are directly related to load, resource, and price assumptions used to develop power  
17 rates. Therefore, they are included in the Power Services revenue forecast.

18  
19 **9.5.1 Augmentation Purchase Expense**

20 For planning purposes, the forecast of firm FCRPS output is based upon critical water  
21 conditions. *See* Power Loads and Resources Study, BP-24-FS-BPA-03, § 3.1.2.1.3. The  
22 forecast annual firm FCRPS output under critical water plus the output of other Federal  
23 resources may not be adequate to meet annual average firm loads. Therefore, system  
24 augmentation is added to Federal resources to balance firm annual resources with firm  
25 annual loads. The forecast expense for the augmentation is based on projected prices using  
26 the Aurora model assuming critical water conditions. *See* Power and Transmission Risk  
27 Study, BP-24-FS-BPA-05, § 4.1.1.2.1. Augmentation purchase amounts for FY 2023-2025

1 are listed in Table 4 of this Study, line 26, and Power Rates Study Documentation, BP-24-  
2 FS-BPA-01A, Table 9.2, line 51.

### 3 4 **9.5.2 Balancing Power Purchases**

5 Balancing power purchases are calculated by RevSim, which finds any monthly HLH and  
6 LLH energy deficits by simulations of 40 games in each of the 30 water years, for a total of  
7 2,700 games, and application of the corresponding market prices developed for each game.  
8 Similar to the treatment of short-term market sales, the median value for balancing  
9 purchases over the 2,700 games is reported for FY 2023 for forecast months and added to  
10 actual purchases in past months, and the median value is reported for FY 2023-2025. Total  
11 balancing purchase expense for FY 2023-2025 is listed in Table 4 of this Study, line 27, and  
12 Power Rates Study Documentation, BP-24-FS-BPA-01A, Table 9.2, line 52. A full  
13 description is found in the Power and Transmission Risk Study, BP-24-FS-BPA-05,  
14 Section 4.1.1.2.2.

### 15 16 **9.5.3 Other Power Purchases**

17 Other power purchases are primarily committed purchases BPA has made to serve  
18 preference customer loads in Southeastern Idaho. In those months and water years in  
19 which firm loads exceed resources, Southeast Idaho Load Service (SILS) purchases reduce  
20 balancing purchases. Conversely, in those months and water years in which resources are  
21 sufficient to serve firm loads, SILS purchases increase the amount of surplus sales. RevSim  
22 accounts for the energy related to SILS purchases in the balancing purchases category.  
23 A full description is found in the Power and Transmission Risk Study, BP-24-FS-BPA-05,  
24 Section 4.1.1.2.1, and in Section 6.6 of this Study.

1 The cost of Tier 2 power is also included in other power purchases, as are other  
2 miscellaneous contracts. Total other power purchase expense for FY 2023-2025 is listed in  
3 Table 4 of this Study, line 28, and Power Rates Study Documentation, BP-24-FS-BPA-01A,  
4 Table 9.2, line 53.

5

## 6 **9.6 Summary of Power Revenues**

7 A detailed summary of power revenues at current and proposed rates is found in Tables 3  
8 and 4 of this Study, and in Power Rates Study Documentation, BP-24-FS-BPA-01A,  
9 Tables 9.1 and 9.2.

## **POWER RATES TABLES**

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**Table 1: Rate Period High Water Marks for FY 2024-2025**

| <b>Table of RHWMs for FY 2024 - FY 2025</b> |                    |                                      |                            |
|---------------------------------------------|--------------------|--------------------------------------|----------------------------|
|                                             | <i>A</i>           | <i>B</i>                             | <i>C</i>                   |
|                                             | <b>Customer ID</b> | <b>Customer Name</b>                 | <b>RHWM<br/>annual aMW</b> |
| 1                                           | 10055              | Albion, City of                      | 0.398                      |
| 2                                           | 10005              | Alder Mutual                         | 0.548                      |
| 3                                           | 10057              | Ashland, City of                     | 21.069                     |
| 4                                           | 10015              | Asotin County PUD #1                 | 0.573                      |
| 5                                           | 10059              | Bandon, City of                      | 7.639                      |
| 6                                           | 10024              | Benton County PUD #1                 | 200.923                    |
| 7                                           | 10025              | Benton REA                           | 59.659                     |
| 8                                           | 10027              | Big Bend Elec Coop                   | 61.194                     |
| 9                                           | 10029              | Blachly Lane Elec Coop               | 17.616                     |
| 10                                          | 10061              | Blaine, City of                      | 8.747                      |
| 11                                          | 10062              | Bonnors Ferry, City of               | 5.320                      |
| 12                                          | 10064              | Burley, City of                      | 14.064                     |
| 13                                          | 10044              | Canby, City of                       | 20.309                     |
| 14                                          | 10065              | Cascade Locks, City of               | 2.378                      |
| 15                                          | 10046              | Central Electric Coop                | 81.851                     |
| 16                                          | 10047              | Central Lincoln PUD                  | 156.673                    |
| 17                                          | 10066              | Centralia, City of                   | 24.371                     |
| 18                                          | 10067              | Cheney, City of                      | 15.817                     |
| 19                                          | 10068              | Chewelah, City of                    | 2.770                      |
| 20                                          | 10101              | Clallam County PUD #1                | 76.028                     |
| 21                                          | 10103              | Clark County PUD #1                  | 318.494                    |
| 22                                          | 10105              | Clatskanie PUD                       | 92.838                     |
| 23                                          | 10106              | Clearwater Power                     | 23.879                     |
| 24                                          | 10109              | Columbia Basin Elec Coop             | 12.118                     |
| 25                                          | 10111              | Columbia Power Coop                  | 3.235                      |
| 26                                          | 10113              | Columbia REA                         | 37.693                     |
| 27                                          | 10112              | Columbia River PUD                   | 58.250                     |
| 28                                          | 10116              | Consolidated Irrigation District #19 | 0.228                      |
| 29                                          | 10118              | Consumers Power                      | 45.674                     |
| 30                                          | 10121              | Coos Curry Elec Coop                 | 40.875                     |
| 31                                          | 10378              | Coulee Dam, City of                  | 2.021                      |
| 32                                          | 10123              | Cowlitz County PUD #1                | 549.199                    |
| 33                                          | 10070              | Declo, City of                       | 0.359                      |

| <b>Table of RHWMs for FY 2024 - FY 2025</b> |                    |                               |                            |
|---------------------------------------------|--------------------|-------------------------------|----------------------------|
|                                             | <i>A</i>           | <i>B</i>                      | <i>C</i>                   |
|                                             | <b>Customer ID</b> | <b>Customer Name</b>          | <b>RHWM<br/>annual aMW</b> |
| 34                                          | 10136              | Douglas Electric Cooperative  | 18.537                     |
| 35                                          | 10071              | Drain, City of                | 1.914                      |
| 36                                          | 10142              | East End Mutual Electric      | 2.687                      |
| 37                                          | 10144              | Eatonville, City of           | 3.368                      |
| 38                                          | 10072              | Ellensburg, City of           | 23.982                     |
| 39                                          | 10156              | Elmhurst Mutual P & L         | 32.238                     |
| 40                                          | 10157              | Emerald PUD                   | 49.958                     |
| 41                                          | 10158              | Energy Northwest              | 2.791                      |
| 42                                          | 10170              | Eugene Water & Electric Board | 251.097                    |
| 43                                          | 10173              | Fall River Elec Coop          | 33.130                     |
| 44                                          | 10174              | Farmers Elec Coop             | 0.507                      |
| 45                                          | 10177              | Ferry County PUD #1           | 11.665                     |
| 46                                          | 10179              | Flathead Elec Coop            | 166.822                    |
| 47                                          | 10074              | Forest Grove, City of         | 26.682                     |
| 48                                          | 10183              | Franklin County PUD #1        | 117.351                    |
| 49                                          | 10186              | Glacier Elec Coop             | 21.317                     |
| 50                                          | 10190              | Grant County PUD #2           | 5.192                      |
| 51                                          | 10191              | Grays Harbor PUD #1           | 131.217                    |
| 52                                          | 10197              | Harney Elec Coop              | 22.753                     |
| 53                                          | 10597              | Hermiston, City of            | 12.937                     |
| 54                                          | 10076              | Heyburn, City of              | 4.817                      |
| 55                                          | 10202              | Hood River Elec Coop          | 13.099                     |
| 56                                          | 10203              | Idaho County L & P            | 6.213                      |
| 57                                          | 10204              | Idaho Falls Power             | 79.556                     |
| 58                                          | 10209              | Inland P & L                  | 104.890                    |
| 59                                          | 12026              | Jefferson County PUD #1       | 45.173                     |
| 60                                          | 13927              | Kalispel Tribe Utility        | 4.073                      |
| 61                                          | 10230              | Kittitas County PUD #1        | 9.702                      |
| 62                                          | 10231              | Klickitat County PUD #1       | 36.659                     |
| 63                                          | 10234              | Kootenai Electric Coop        | 50.999                     |
| 64                                          | 10235              | Lakeview L & P (WA)           | 33.113                     |
| 65                                          | 10236              | Lane County Elec Coop         | 29.103                     |
| 66                                          | 10237              | Lewis County PUD #1           | 113.732                    |
| 67                                          | 10239              | Lincoln Elec Coop (MT)        | 14.000                     |

| <b>Table of RHWMs for FY 2024 - FY 2025</b> |                    |                                        |                            |
|---------------------------------------------|--------------------|----------------------------------------|----------------------------|
|                                             | <i>A</i>           | <i>B</i>                               | <i>C</i>                   |
|                                             | <b>Customer ID</b> | <b>Customer Name</b>                   | <b>RHWM<br/>annual aMW</b> |
| 68                                          | 10242              | Lost River Elec Coop                   | 9.526                      |
| 69                                          | 10244              | Lower Valley Energy                    | 86.038                     |
| 70                                          | 10246              | Mason County PUD #1                    | 8.987                      |
| 71                                          | 10247              | Mason County PUD #3                    | 79.929                     |
| 72                                          | 10078              | McCleary, City of                      | 3.718                      |
| 73                                          | 10079              | McMinnville, City of                   | 88.179                     |
| 74                                          | 10256              | Midstate Elec Coop                     | 46.746                     |
| 75                                          | 10080              | Milton, Town of                        | 7.437                      |
| 76                                          | 10081              | Milton-Freewater, City of              | 10.455                     |
| 77                                          | 10082              | Minidoka, City of                      | 0.118                      |
| 78                                          | 10258              | Mission Valley                         | 37.952                     |
| 79                                          | 10259              | Missoula Elec Coop                     | 26.985                     |
| 80                                          | 10260              | Modern Elec Coop                       | 26.285                     |
| 81                                          | 10083              | Monmouth, City of                      | 8.363                      |
| 82                                          | 10273              | Nespelem Valley Elec Coop              | 5.881                      |
| 83                                          | 10278              | Northern Lights                        | 35.928                     |
| 84                                          | 10279              | Northern Wasco County PUD              | 64.765                     |
| 85                                          | 10284              | Ohop Mutual Light Company              | 10.158                     |
| 86                                          | 10285              | Okanogan County Elec Coop              | 6.529                      |
| 87                                          | 10286              | Okanogan County PUD #1                 | 45.911                     |
| 88                                          | 10288              | Orcas P & L                            | 24.734                     |
| 89                                          | 10291              | Oregon Trail Coop                      | 79.182                     |
| 90                                          | 10294              | Pacific County PUD #2                  | 36.327                     |
| 91                                          | 10304              | Parkland L & W                         | 14.068                     |
| 92                                          | 10306              | Pend Oreille County PUD #1             | 25.769                     |
| 93                                          | 10307              | Peninsula Light Company                | 71.985                     |
| 94                                          | 10086              | Plummer, City of                       | 3.945                      |
| 95                                          | 10298              | PNGC Aggregate                         | 602.276                    |
| 96                                          | 10087              | Port Angeles, City of                  | 85.480                     |
| 97                                          | 10706              | Port of Seattle - SETAC In'tl. Airport | 17.278                     |
| 98                                          | 10331              | Raft River Elec Coop                   | 36.602                     |
| 99                                          | 10333              | Ravalli County Elec Coop               | 18.515                     |
| 100                                         | 10089              | Richland, City of                      | 104.213                    |
| 101                                         | 10338              | Riverside Elec Coop                    | 2.373                      |

| <b>Table of RHWMs for FY 2024 - FY 2025</b> |                    |                                         |                            |
|---------------------------------------------|--------------------|-----------------------------------------|----------------------------|
|                                             | <i>A</i>           | <i>B</i>                                | <i>C</i>                   |
|                                             | <b>Customer ID</b> | <b>Customer Name</b>                    | <b>RHWM<br/>annual aMW</b> |
| 102                                         | 10091              | Rupert, City of                         | 9.422                      |
| 103                                         | 10342              | Salem Elec Coop                         | 38.691                     |
| 104                                         | 10343              | Salmon River Elec Coop                  | 31.389                     |
| 105                                         | 10349              | Seattle City Light                      | 523.911                    |
| 106                                         | 10352              | Skamania County PUD #1                  | 15.907                     |
| 107                                         | 10354              | Snohomish County PUD #1                 | 799.070                    |
| 108                                         | 10094              | Soda Springs, City of                   | 3.037                      |
| 109                                         | 10360              | Southside Elec Lines                    | 6.765                      |
| 110                                         | 10363              | Springfield Utility Board               | 100.706                    |
| 111                                         | 10379              | Steilacoom, Town of                     | 4.808                      |
| 112                                         | 10095              | Sumas, Town of                          | 3.643                      |
| 113                                         | 10369              | Surprise Valley Elec Coop               | 16.432                     |
| 114                                         | 10370              | Tacoma Public Utilities                 | 402.390                    |
| 115                                         | 10371              | Tanner Elec Coop                        | 11.032                     |
| 116                                         | 10376              | Tillamook PUD #1                        | 56.029                     |
| 117                                         | 10097              | Troy, City of                           | 2.038                      |
| 118                                         | 10172              | U.S. Airforce Base, Fairchild           | 6.102                      |
| 119                                         | 10406              | U.S. DOE Albany Research Center         | 0.458                      |
| 120                                         | 10426              | U.S. DOE Richland Operations Office     | 36.539                     |
| 121                                         | 10326              | U.S. Naval Base, Bremerton              | 30.460                     |
| 122                                         | 10408              | U.S. Naval Station, Everett (Jim Creek) | 1.527                      |
| 123                                         | 10409              | U.S. Naval Submarine Base, Bangor       | 20.421                     |
| 124                                         | 10388              | Umatilla Elec Coop                      | 113.223                    |
| 125                                         | 10482              | Umpqua Indian Utility Cooperative       | 4.114                      |
| 126                                         | 10391              | United Electric Coop                    | 29.977                     |
| 127                                         | 10434              | Vera Irrigation District                | 27.157                     |
| 128                                         | 10436              | Vigilante Elec Coop                     | 19.152                     |
| 129                                         | 10440              | Wahkiakum County PUD #1                 | 5.005                      |
| 130                                         | 10442              | Wasco Elec Coop                         | 13.396                     |
| 131                                         | 11680              | Weiser, City of                         | 6.329                      |
| 132                                         | 10446              | Wells Rural Elec Coop                   | 95.771                     |
| 133                                         | 10448              | West Oregon Elec Coop                   | 8.481                      |
| 134                                         | 10451              | Whatcom County PUD #1                   | 26.833                     |
| 135                                         | 10502              | Yakama Power                            | 18.707                     |

**Table 2: Overview of BP-24 Initial Proposal Rates**

Tiered PF Rate Summary

| 1  | A                                                   | B                        | C                    | D             |
|----|-----------------------------------------------------|--------------------------|----------------------|---------------|
| 2  |                                                     | <b>BP-24</b>             | <b>% above BP-22</b> |               |
| 3  | <b>Unbifurcated PF</b>                              | \$ 48.27                 | 7.8%                 |               |
| 4  | <b>PF Public (Tier 1 + Tier 2)</b>                  | \$ 35.81                 | 2.7%                 |               |
| 5  | <b>PF Exchange</b>                                  | \$ 70.49                 | 13.7%                |               |
| 6  | <b>IP</b>                                           | \$ 41.38                 | 1.7%                 |               |
| 7  | <b>NR</b>                                           | \$ 85.35                 | 8.3%                 |               |
| 8  |                                                     |                          |                      |               |
| 9  | <b>Annual Average \$ (1000s)</b>                    | <b>BP-22</b>             | <b>BP-24</b>         | <b>Change</b> |
| 10 | <b>Composite Rate Revenues</b>                      | \$2,275,475              | \$2,380,887          | 4.6%          |
| 11 | <b>Non-Slice Rate Revenues</b>                      | \$(287,145)              | \$(331,991)          | -15.6%        |
| 12 | <b>Slice Rate Revenues</b>                          | \$-                      | \$-                  |               |
| 13 | <b>Load Shaping Rate Revenues</b>                   | \$17,898                 | \$60,953             | 240.6%        |
| 14 | <b>Demand Rate Revenues</b>                         | \$55,457                 | \$61,442             | 10.8%         |
| 15 | <b>Tier 1 Revenue Requirement</b>                   | \$2,061,684              | \$2,171,291          | 5.3%          |
| 16 | <b>Tier 2 Revenue Requirement</b>                   | \$47,492                 | \$160,289            | 237.5%        |
| 17 | <b>Value of Slice Surplus</b>                       | \$(106,183)              | \$(111,312)          | -4.8%         |
| 18 | <b>Value of CHWM RECs (credit)</b>                  | Not applicable for BP-24 |                      |               |
| 19 | <b>Lookback Return (credit)</b>                     | Not applicable for BP-24 |                      |               |
| 20 | <b>Net Power Cost to All PF</b>                     | \$2,002,993              | \$2,220,268          | 10.8%         |
| 21 | <b>Surcharges</b>                                   | \$-                      | \$-                  |               |
| 22 | <b>Annual PF Load (w/firm Slice) (GWh)</b>          | 57,436                   | 61,938               | 7.9%          |
| 23 | <b>PF Average Net Cost (\$/MWh)</b>                 | \$ 34.87                 | \$ 35.82             | 2.7%          |
| 24 |                                                     |                          |                      |               |
| 25 | <b>Tier 1 Average Net Cost without FRP (\$/MWh)</b> | \$ 34.93                 | \$ 34.69             | -0.7%         |
| 26 | <b>Tier 1 Average Net Cost max FRP (\$/MWh)</b>     | Not applicable for BP-24 |                      |               |
| 27 | <b>Tier 2 Short-Term (\$/MWh)</b>                   | \$ 33.65                 | \$ 61.50             | 82.7%         |
| 28 |                                                     |                          |                      |               |
| 29 | <b>Slice Sales</b>                                  | <b>BP-22</b>             | <b>BP-24</b>         | <b>Change</b> |
| 30 | <b>Composite+Slice</b>                              | \$536,279                | \$491,768            |               |
| 31 | <b>Surcharges</b>                                   | \$-                      | \$-                  |               |
| 32 | <b>Tier 1 Average Cost (\$/MWh)</b>                 | \$40.65                  | \$40.21              | -1.1%         |
| 33 | <b>Value of Slice Surplus Credits</b>               | \$(106,183)              | \$(111,312)          |               |
| 34 | <b>Net Cost of Slice Power</b>                      | \$430,097                | \$380,456            |               |
| 35 | <b>Tier 1 Average Net Cost (\$/MWh)</b>             | \$ 32.59                 | \$ 31.11             | -4.6%         |
| 36 |                                                     |                          |                      |               |
| 37 | <b>Non-Slice Sales</b>                              | <b>BP-22</b>             | <b>BP-24</b>         | <b>Change</b> |
| 38 | <b>Composite+NonSlice+Shape+Demand</b>              | \$1,525,503              | \$1,679,622          |               |
| 39 | <b>Tier 1 Average Cost (\$/MWh)</b>                 | \$35.64                  | \$35.63              | -0.1%         |
| 40 | <b>Credits</b>                                      | \$-                      | \$-                  |               |
| 41 | <b>Net Cost of Non-Slice Power</b>                  | \$1,525,503              | \$1,679,622          |               |
| 42 | <b>Surcharges</b>                                   | Not applicable for BP-24 |                      |               |
| 43 | <b>Tier 1 Average Net Cost without FRP (\$/MWh)</b> | \$ 35.64                 | \$ 35.63             | 0.0%          |
| 44 | <b>Tier 1 Average Net Cost max FRP (\$/MWh)</b>     | Not applicable for BP-24 |                      |               |
| 45 |                                                     |                          |                      |               |
| 46 | <b>Tiered PF Rate Components</b>                    | <b>BP-22</b>             | <b>BP-24</b>         | <b>Change</b> |
| 47 | <b>Composite Rate (\$/ pct/month)</b>               | \$1,998,422              | \$2,075,946          | 3.9%          |
| 48 | <b>Non-Slice Rate (\$/ pct/month)</b>               | \$(329,943)              | \$(364,823)          | 10.6%         |

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**Table 3: Revenues at Current Rates**

|    | B                                | C | D | E                                              | F                  | G             | H                  | I            | J                  | K             |
|----|----------------------------------|---|---|------------------------------------------------|--------------------|---------------|--------------------|--------------|--------------------|---------------|
| 1  | <b>Revenues at Current Rates</b> |   |   |                                                | <b>2023</b>        |               | <b>2024</b>        |              | <b>2025</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>    |
| 3  |                                  |   |   | Composite Revenue                              | \$2,327,617        | 5,032         | \$2,262,599        | 5,353        | \$2,262,599        | 6,755         |
| 4  |                                  |   |   | Non-Slice Revenue                              | (\$295,754)        | -             | (\$285,038)        | -            | (\$285,038)        | -             |
| 5  |                                  |   |   | Slice                                          | \$0                | 2,684         | \$0                | 1,405        | \$0                | 1,388         |
| 6  |                                  |   |   | Load Shaping Revenue                           | \$24,160           | 21            | \$25,411           | 11           | \$29,399           | 26            |
| 7  |                                  |   |   | Demand Revenue                                 | \$55,946           | -             | \$54,677           | -            | \$55,163           | -             |
| 8  |                                  |   |   | Irrigation Rate Discount                       | (\$20,509)         | -             | (\$20,905)         | -            | (\$20,905)         | -             |
| 9  |                                  |   |   | Low Density Discount                           | (\$38,109)         | -             | (\$39,746)         | -            | (\$39,746)         | -             |
| 10 |                                  |   |   | Tier 2                                         | \$48,973           | 173           | \$54,964           | 211          | \$52,582           | 394           |
| 11 |                                  |   |   | RSS (Non-Federal) and Other                    | \$1,052            | -             | \$1,115            | -            | \$1,115            | -             |
| 12 |                                  |   |   | PF customers (CHWM) sub-total                  | \$2,103,374        | 7,910         | \$2,053,077        | 6,980        | \$2,055,171        | 8,563         |
| 13 |                                  |   |   | NR sub-total                                   | \$0                | -             | \$0                | -            | \$0                | -             |
| 14 |                                  |   |   | DSIs sub-total                                 | \$4,279            | 12            | \$3,933            | 11           | \$3,921            | 11            |
| 15 |                                  |   |   | FPS sub-total                                  | \$8,577            | -             | \$9,004            | -            | \$9,206            | -             |
| 16 |                                  |   |   | Short-term market sales sub-total              | \$761,014          | 1,644         | \$638,012          | 1,619        | \$575,152          | 1,585         |
| 17 |                                  |   |   | Long Term Contractual Obligations sub-total    | \$0                | -             | \$0                | -            | \$0                | -             |
| 18 |                                  |   |   | Canadian Entitlement Return                    | \$0                | 462           | \$0                | 462          | \$0                | 462           |
| 19 |                                  |   |   | Other Sales sub-total                          | \$8,337            | -             | \$0                | -            | \$0                | -             |
| 20 |                                  |   |   | <b>Gross Sales</b>                             | <b>\$2,885,582</b> | <b>10,028</b> | <b>\$2,704,026</b> | <b>9,072</b> | <b>\$2,643,449</b> | <b>10,622</b> |
| 21 |                                  |   |   | <b>Miscellaneous Revenues</b>                  | <b>\$24,463</b>    | <b>175</b>    | <b>\$24,230</b>    | <b>175</b>   | <b>\$24,217</b>    | <b>175</b>    |
| 22 |                                  |   |   | <b>Generation Inputs / Inter-business line</b> | <b>\$100,170</b>   | <b>9</b>      | <b>\$110,911</b>   | <b>9</b>     | <b>\$113,260</b>   | <b>9</b>      |
| 23 |                                  |   |   | 4(h)(10)(c)                                    | \$97,995           | -             | \$111,288          | -            | \$111,456          | -             |
| 24 |                                  |   |   | Colville Settlement                            | \$4,600            | -             | \$4,600            | -            | \$4,600            | -             |
| 25 |                                  |   |   | <b>Treasury Credits</b>                        | <b>\$102,595</b>   | <b>-</b>      | <b>\$115,888</b>   | <b>-</b>     | <b>\$116,056</b>   | <b>-</b>      |
| 26 |                                  |   |   | Augmentation Power Purchase total              | \$0                | -             | \$0                | -            | \$0                | -             |
| 27 |                                  |   |   | Balancing Power Purchase sub-total             | \$60,055           | 100           | \$80,601           | 173          | \$70,802           | 153           |
| 28 |                                  |   |   | Other Power Purchase total                     | \$47,041           | 175           | \$111,871          | 217          | \$200,414          | 407           |
| 29 |                                  |   |   | <b>Power Purchases</b>                         | <b>\$107,096</b>   | <b>275</b>    | <b>\$192,472</b>   | <b>389</b>   | <b>\$271,215</b>   | <b>560</b>    |

**Table 4: Revenues at Proposed Rates**

|    | B                                 | C | D | E                                              | F                  | G             | H                  | I            | J                  | K             |
|----|-----------------------------------|---|---|------------------------------------------------|--------------------|---------------|--------------------|--------------|--------------------|---------------|
| 1  | <b>Revenues at Proposed Rates</b> |   |   |                                                | <b>2023</b>        |               | <b>2024</b>        |              | <b>2025</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>    |
| 3  |                                   |   |   | Composite Revenue                              | \$2,327,617        | 5,032         | \$2,376,037        | 5,353        | \$2,385,737        | 6,755         |
| 4  |                                   |   |   | Non-Slice Revenue                              | (\$295,754)        | -             | (\$331,138)        | -            | (\$332,843)        | -             |
| 5  |                                   |   |   | Slice                                          | \$0                | 2,684         | \$0                | 1,405        | \$0                | 1,388         |
| 6  |                                   |   |   | Load Shaping Revenue                           | \$24,160           | 21            | \$57,931           | 11           | \$63,975           | 26            |
| 7  |                                   |   |   | Demand Revenue                                 | \$55,946           | -             | \$60,247           | -            | \$62,636           | -             |
| 8  |                                   |   |   | Irrigation Rate Discount                       | (\$20,509)         | -             | (\$21,770)         | -            | (\$21,770)         | -             |
| 9  |                                   |   |   | Low Density Discount                           | (\$38,109)         | -             | (\$37,701)         | -            | (\$38,532)         | -             |
| 10 |                                   |   |   | Tier 2                                         | \$48,973           | 173           | \$114,787          | 211          | \$205,792          | 394           |
| 11 |                                   |   |   | RSS (Non-Federal) and Other                    | \$1,052            | -             | \$964              | -            | \$944              | -             |
| 12 |                                   |   |   | PF customers (CHWM) sub-total                  | \$2,103,374        | 7,910         | \$2,219,356        | 6,980        | \$2,325,939        | 8,563         |
| 13 |                                   |   |   | NR sub-total                                   | \$0                | -             | \$0                | -            | \$0                | -             |
| 14 |                                   |   |   | DSIs sub-total                                 | \$4,279            | 12            | \$4,001            | 11           | \$3,988            | 11            |
| 15 |                                   |   |   | FPS sub-total                                  | \$8,577            | -             | \$9,004            | -            | \$9,206            | -             |
| 16 |                                   |   |   | Short-term market sales sub-total              | \$761,014          | 1,644         | \$638,012          | 1,619        | \$575,152          | 1,585         |
| 17 |                                   |   |   | Long Term Contractual Obligations sub-total    | \$0                | -             | \$0                | -            | \$0                | -             |
| 18 |                                   |   |   | Canadian Entitlement Return                    | \$0                | 462           | \$0                | 462          | \$0                | 462           |
| 19 |                                   |   |   | Other Sales sub-total                          | \$8,337            | -             | \$0                | -            | \$0                | -             |
| 20 |                                   |   |   | <b>Gross Sales</b>                             | <b>\$2,885,582</b> | <b>10,028</b> | <b>\$2,870,373</b> | <b>9,072</b> | <b>\$2,914,285</b> | <b>10,622</b> |
| 21 |                                   |   |   | <b>Miscellaneous Revenues</b>                  | <b>\$24,463</b>    | <b>175</b>    | <b>\$24,230</b>    | <b>175</b>   | <b>\$24,217</b>    | <b>175</b>    |
| 22 |                                   |   |   | <b>Generation Inputs / Inter-business line</b> | <b>\$100,170</b>   | <b>9</b>      | <b>\$110,911</b>   | <b>9</b>     | <b>\$113,260</b>   | <b>9</b>      |
| 23 |                                   |   |   | 4(h)(10)(c)                                    | \$97,995           | -             | \$111,288          | -            | \$111,456          | -             |
| 24 |                                   |   |   | Colville Settlement                            | \$4,600            | -             | \$4,600            | -            | \$4,600            | -             |
| 25 |                                   |   |   | <b>Treasury Credits</b>                        | <b>\$102,595</b>   | <b>-</b>      | <b>\$115,888</b>   | <b>-</b>     | <b>\$116,056</b>   | <b>-</b>      |
| 26 |                                   |   |   | Augmentation Power Purchase total              | \$0                | -             | \$0                | -            | \$0                | -             |
| 27 |                                   |   |   | Balancing Power Purchase sub-total             | \$60,055           | 100           | \$80,601           | 173          | \$70,802           | 153           |
| 28 |                                   |   |   | Other Power Purchase total                     | \$47,041           | 175           | \$111,871          | 217          | \$200,414          | 407           |
| 29 |                                   |   |   | <b>Power Purchases</b>                         | <b>\$107,096</b>   | <b>275</b>    | <b>\$192,472</b>   | <b>389</b>   | <b>\$271,215</b>   | <b>560</b>    |



**Table 5: Adjustments to Financial Reserves Base Amount**

|    | 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<br>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 2024</b> | <b>FY 2025</b> |                  |
| 2  | Avista Corporation                | \$16,150       | \$16,150       |                  |
| 3  | Idaho Power Company               | \$22,903       | \$22,903       |                  |
| 4  | NorthWestern Energy, LLC          | \$5,922        | \$5,922        |                  |
| 5  | PacifiCorp                        | \$74,665       | \$74,665       |                  |
| 6  | Portland General Electric Company | \$62,057       | \$62,057       |                  |
| 7  | Puget Sound Energy, Inc.          | \$91,904       | \$91,904       |                  |
| 8  | <b>Net IOU Exchange</b>           | \$273,600      | \$273,600      | <b>\$273,600</b> |
| 9  | <b>Refund Amt</b>                 | \$ -           | \$ -           | <b>\$ -</b>      |
| 10 |                                   |                |                |                  |
| 11 | Clark Public Utilities            | \$ -           | \$ -           |                  |
| 12 | Franklin                          | \$ -           | \$ -           |                  |
| 13 | Snohomish County PUD No 1         | \$623          | \$623          |                  |
| 14 | <b>Net COU Exchange</b>           | \$623          | \$623          | <b>\$623</b>     |
| 15 |                                   |                | Total          | <b>\$274,220</b> |

## **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-24 energy rates, which become the energy rates used in the IP-24 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-24 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* § 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-24 RATE CASE**

BPA did not conduct a new industrial margin survey for the BP-24 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-24 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 1.33. The BP-24 industrial margin is 0.910 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>    |

### 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 #<br/>of customers</u> | <u>Load<br/>(kWh)</u> | <u>Monthly<br/>basic<br/>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> |

| <b>Utility Number: # 5</b>   |                         |                     |                     |                     |                  |                  |                     |
|------------------------------|-------------------------|---------------------|---------------------|---------------------|------------------|------------------|---------------------|
|                              | <b>Large Industrial</b> | <b>Production</b>   | <b>Transmission</b> | <b>Distribution</b> | <b>Other</b>     | <b>Taxes</b>     | <b>Sum</b>          |
| <b>Production:</b>           | \$ 1,574,999            | \$ 1,574,999        |                     |                     |                  |                  | \$ 1,574,999        |
| <b>Transmission:</b>         | \$ 14,196               |                     | \$ 14,196           |                     |                  |                  | \$ 14,196           |
| <b>Distribution:</b>         | \$ 310,053              |                     |                     | \$ 310,053          |                  |                  | \$ 310,053          |
| <b>Customer Accounts:</b>    | \$ 7,316                |                     |                     |                     | \$ 7,316         |                  | \$ 7,316            |
| <b>Meter Reading:</b>        | \$ 194                  |                     |                     | \$ 194.00           |                  |                  | \$ 194              |
| <b>Customer Service:</b>     | \$ 3,456                |                     |                     |                     | \$ 3,456         |                  | \$ 3,456            |
| <b>Sales Exp:</b>            | \$ 2,549                |                     |                     |                     | \$ 2,549         |                  | \$ 2,549            |
| <b>Admin &amp; Genl (1):</b> | \$ 120,230              |                     | \$ 5,056            | \$ 110,429          | \$ 4,744         |                  | \$ 120,230          |
| <b>Depreciation:</b>         | \$ 232,235              |                     | \$ 10,168           | \$ 222,067          |                  |                  | \$ 232,235          |
| <b>Taxes:</b>                | \$ 34,108               |                     |                     |                     |                  | \$ 34,108        | \$ 34,108           |
| <b>Interest:</b>             | \$ 159,676              |                     | \$ 6,991            | \$ 152,685          |                  |                  | \$ 159,676          |
| <b>Other:</b>                | \$ 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                  |
|-------------------------------|--------------------------|----------------------|---------------------|---------------------|-------------------|---------------------|----------------------|
| Power:                        | \$ 15,244,327            | \$ 15,244,327        |                     |                     |                   |                     | \$ 15,244,327        |
| Transmission:                 | \$ 2,544,405             |                      | \$ 2,544,405        |                     |                   |                     | \$ 2,544,405         |
| Distribution:                 | \$ 1,481,945             |                      |                     | \$ 1,481,945        |                   |                     | \$ 1,481,945         |
| Meter Reading + Cust Records: | \$ 5,366                 |                      |                     | \$ 5,366            |                   |                     | \$ 5,366             |
| Customer Education:           | \$ 77,324                |                      |                     |                     | \$ 77,324         |                     | \$ 77,324            |
| Low Income Assist.:           | \$ 156,540               |                      |                     |                     | \$ 156,540        |                     | \$ 156,540           |
| Electric Marketing:           | \$ 142,594               |                      |                     |                     | \$ 142,594        |                     | \$ 142,594           |
| Taxes:                        | \$ 1,419,465             |                      |                     |                     |                   | \$ 1,419,465        | \$ 1,419,465         |
| <b>TOTAL</b>                  | <b>\$ 21,071,966</b>     | <b>\$ 15,244,327</b> | <b>\$ 2,544,405</b> | <b>\$ 1,487,311</b> | <b>\$ 376,458</b> | <b>\$ 1,419,465</b> | <b>\$ 21,071,966</b> |

| 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> |

## Utility Number: # 13

|                   | Large Industrial    | Production          | Transmission | Distribution    | Other           | Taxes             | Sum                 |
|-------------------|---------------------|---------------------|--------------|-----------------|-----------------|-------------------|---------------------|
| Purchased Power:  | \$ 3,813,592        | \$ 3,813,592        |              |                 |                 |                   | \$ 3,813,592        |
| Transmission      |                     |                     |              |                 |                 |                   |                     |
| Distribution      |                     |                     |              |                 |                 |                   |                     |
| Conservation      | \$ 600,000          | \$ 600,000          |              |                 |                 |                   | \$ 600,000          |
| Meters & Services | \$ 4,742            |                     |              | \$ 4,742        |                 |                   | \$ 4,742            |
| Accounting        | \$ 536              |                     |              |                 | \$ 536          |                   | \$ 536              |
| Customer Related  | \$ 789              |                     |              |                 | \$ 789          |                   | \$ 789              |
| Revenue Related   | \$ 250,374          |                     |              |                 |                 | \$ 250,374        | \$ 250,374          |
| <b>TOTAL</b>      | <b>\$ 4,670,033</b> | <b>\$ 4,413,592</b> |              | <b>\$ 4,742</b> | <b>\$ 1,325</b> | <b>\$ 250,374</b> | <b>\$ 4,670,033</b> |

## 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**

| Utility Number: # 23       |                    |                    |                |                  |                 |                 |                    |
|----------------------------|--------------------|--------------------|----------------|------------------|-----------------|-----------------|--------------------|
|                            | Industrial         | Production         | Transmission   | Distribution     | Other           | Taxes           | Sum                |
| Purchased Power:           | \$ 2,626,334       | \$ 2,626,334       |                |                  |                 |                 | \$ 2,626,334       |
| Transmission:              |                    |                    |                |                  |                 |                 |                    |
| Distribution:              | \$ 318,070         |                    |                | \$ 318,070       |                 |                 | \$ 318,070         |
| Customer Services & Accts: | \$ 63,752          |                    |                | \$ 9,575         | \$ 54,177       |                 | \$ 63,752          |
| A & G:                     | \$ 155,355         | \$ 11,293          |                | \$ 130,111       | \$ 13,951       |                 | \$ 155,355         |
| Depreciation:              | \$ 141,272         |                    | \$ 9,761       | \$ 112,513       | \$ 18,998       |                 | \$ 141,272         |
| Interest:                  | \$ 77,847          |                    |                | \$ 77,847        |                 |                 | \$ 77,847          |
| Taxes:                     | \$ 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<br>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<br>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**

**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<br>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**

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