

BP-14 Final Rate Proposal

Power Rates Study

BP-14-FS-BPA-01

July 2013



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COMMONLY USED ACRONYMS AND SHORT FORMS

| | |
|------------------------------------|--|
| AAC | Anticipated Accumulation of Cash |
| AGC | Automatic Generation Control |
| ALF | Agency Load Forecast (computer model) |
| aMW | average megawatt(s) |
| AMNR | Accumulated Modified Net Revenues |
| ANR | Accumulated Net Revenues |
| ASC | Average System Cost |
| BiOp | Biological Opinion |
| BPA | Bonneville Power Administration |
| Btu | British thermal unit |
| CDD | cooling degree day(s) |
| CDQ | Contract Demand Quantity |
| CGS | Columbia Generating Station |
| CHWM | Contract High Water Mark |
| COE, Corps, or USACE Commission | U.S. Army Corps of Engineers Federal Energy Regulatory Commission |
| Corps, COE, or USACE | U.S. Army Corps of Engineers |
| COSA | Cost of Service Analysis |
| COU | consumer-owned utility |
| Council or NPCC | Northwest Power and Conservation Council |
| CP | Coincidental Peak |
| CRAC | Cost Recovery Adjustment Clause |
| CSP | Customer System Peak |
| CT | combustion turbine |
| CY | calendar year (January through December) |
| DDC | Dividend Distribution Clause |
| <i>dec</i> | decrease, decrement, or decremental |
| DERBS | Dispatchable Energy Resource Balancing Service |
| DFS | Diurnal Flattening Service |
| DOE | Department of Energy |
| DSI | direct-service industrial customer or direct-service industry |
| DSO | Dispatcher Standing Order |
| EIA | Energy Information Administration |
| EIS | Environmental Impact Statement |
| EN | Energy Northwest, Inc. |
| EPP | Environmentally Preferred Power |
| ESA | Endangered Species Act |
| 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 |
| FHFO | Funds Held for Others |
| FORS | Forced Outage Reserve Service |

| | |
|---------------------|--|
| FPS | Firm Power Products and Services (rate) |
| FY | fiscal year (October through September) |
| GARD | Generation and Reserves Dispatch (computer model) |
| GEP | Green Energy Premium |
| GRSPs | General Rate Schedule Provisions |
| GTA | General Transfer Agreement |
| GWh | gigawatthour |
| HDD | heating degree day(s) |
| HLH | Heavy Load Hour(s) |
| HOSS | Hourly Operating and Scheduling Simulator (computer model) |
| HYDSIM | Hydrosystem Simulator (computer model) |
| ICE | Intercontinental Exchange |
| <i>inc</i> | increase, increment, or incremental |
| IOU | investor-owned utility |
| IP | Industrial Firm Power (rate) |
| IPR | Integrated Program Review |
| IRD | Irrigation Rate Discount |
| IRM | Irrigation Rate Mitigation |
| IRMP | Irrigation Rate Mitigation Product |
| JOE | Joint Operating Entity |
| kW | kilowatt (1000 watts) |
| kWh | kilowatthour |
| LDD | Low Density Discount |
| LLH | Light Load Hour(s) |
| LRA | Load Reduction Agreement |
| Maf | million acre-feet |
| Mid-C | Mid-Columbia |
| MMBtu | million British thermal units |
| MNR | Modified Net Revenues |
| MRNR | Minimum Required Net Revenue |
| MW | megawatt (1 million watts) |
| MWh | megawatthour |
| NCP | Non-Coincidental Peak |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Corporation |
| NFB | National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) |
| NLSL | New Large Single Load |
| NMFS | National Marine Fisheries Service |
| NOAA Fisheries | National Oceanographic and Atmospheric Administration Fisheries |
| NORM | Non-Operating Risk Model (computer model) |
| Northwest Power Act | Pacific Northwest Electric Power Planning and Conservation Act |
| NPCC or Council | Pacific Northwest Electric Power and Conservation Planning Council |

| | |
|---------------------|--|
| NPV | net present value |
| NR | New Resource Firm Power (rate) |
| NT | Network Transmission |
| NTSA | Non-Treaty Storage Agreement |
| NUG | non-utility generation |
| NWPP | Northwest Power Pool |
| OATT | Open Access Transmission Tariff |
| O&M | operation and maintenance |
| OATI | Open Access Technology International, Inc. |
| OMB | Office of Management and Budget |
| OY | operating year (August through July) |
| PF | Priority Firm Power (rate) |
| PFp | Priority Firm Public (rate) |
| PFx | Priority Firm Exchange (rate) |
| 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 |
| POM | Point of Metering |
| POR | Point of Receipt |
| Project Act | Bonneville Project Act |
| PRS | Power Rates Study |
| PS | BPA Power Services |
| PSW | Pacific Southwest |
| PTP | Point to Point Transmission (rate) |
| PUD | public or people's utility district |
| RAM | Rate Analysis Model (computer model) |
| RAS | Remedial Action Scheme |
| RD | Regional Dialogue |
| REC | Renewable Energy Certificate |
| Reclamation or USBR | U.S. Bureau of Reclamation |
| REP | Residential Exchange Program |
| RevSim | Revenue Simulation Model (component of RiskMod) |
| RFA | Revenue Forecast Application (database) |
| RHWM | Rate Period High Water Mark |
| RiskMod | Risk Analysis Model (computer model) |
| RiskSim | Risk Simulation Model (component of RiskMod) |
| ROD | Record of Decision |
| RPSA | Residential Purchase and Sale Agreement |
| RR | Resource Replacement (rate) |
| RRS | Resource Remarketing Service |
| RSS | Resource Support Services |
| RT1SC | RHWM Tier 1 System Capability |
| RTO | Regional Transmission Operator |
| SCADA | Supervisory Control and Data Acquisition |

| | |
|-------------------------|--|
| SCS | Secondary Crediting Service |
| Slice | Slice of the System (product) |
| T1SFCO | Tier 1 System Firm Critical Output |
| TCMS | Transmission Curtailment Management Service |
| TOCA | Tier 1 Cost Allocator |
| TPP | Treasury Payment Probability |
| TRAM | Transmission Risk Analysis Model |
| Transmission System Act | Federal Columbia River Transmission System Act |
| TRL | Total Retail Load |
| TRM | Tiered Rate Methodology |
| TS | BPA Transmission Services |
| TSS | Transmission Scheduling Service |
| UAI | Unauthorized Increase |
| ULS | Unanticipated Load Service |
| USACE, Corps, or COE | U.S. Army Corps of Engineers |
| USBR or Reclamation | U.S. Bureau of Reclamation |
| USFWS | U.S. Fish and Wildlife Service |
| VERBS | Variable Energy Resources Balancing Service (rate) |
| VOR | Value of Reserves |
| VR1-2014 | First Vintage rate of the BP-14 rate period |
| WECC | Western Electricity Coordinating Council (formerly WSCC) |
| WIT | Wind Integration Team |
| WSPP | Western Systems Power Pool |

1 **1. INTRODUCTION AND BACKGROUND**

2 **1.1 Power Rates Study Overview**

3 The Power Rates Study (Study) explains the processes and calculations used to develop the
4 power rates and billing determinants for BPA’s wholesale power products and services. The
5 Study serves three primary purposes: (1) to demonstrate that the rates have been developed in a
6 manner consistent with statutory direction, including the initial allocation of costs and the
7 subsequent reallocations directed by statute; (2) to set rates consistent with agency policy; and
8 (3) to demonstrate that the rates have been set at a level that recovers the allocated power
9 revenue requirement for the upcoming rate period. The rate design process is illustrated in
10 section 1 of the Power Rates Study Documentation (Documentation), BP-14-FS-BPA-01A, and
11 described further throughout this Study.

12
13 The development of rates in the Study uses inputs from a variety of sources. Loads and
14 resources are provided to the Study by the Power Loads and Resources Study, BP-14-FS-
15 BPA-03, and its accompanying documentation, BP-14-FS-BPA-03A. Power revenue
16 requirement information is provided by the Power Revenue Requirement Study, BP-14-FS-
17 BPA-02, and its accompanying documentation, BP-14-FS-BPA-02A. The Power Risk and
18 Market Price Study, BP-14-FS-BPA-04, and its accompanying documentation, BP-14-FS-
19 BPA-04A, provide the Study with the electricity market price forecasts and forecast quantities of
20 power expected to be sold and purchased in electric markets. These market price forecasts are
21 used in the development of the demand rates, load shaping rates, short-term balancing purchases
22 and expenses, augmentation purchases and expenses, secondary energy sales and revenue, and
23 Planned Net Revenues for Risk (PNRR), if any. The results of the Generation Inputs Study,
24 BP-14-FS-BPA-05, are provided to the Study as revenue credits. Explanation and
25 documentation for these credits arising from generation inputs and other inter-business line cost
26 allocations are included in the Generation Inputs Study.

1 The results of the power rate development process, including rates for power products and
2 services, plus general rate schedule provisions, appear in the Power Rate Schedules,
3 BP-14-A-03-AP01. The revenues resulting from the rates developed herein are used by the
4 Power Revenue Requirement Study in the Revised Revenue Test to test the adequacy of the rates
5 in recovering expenses and supplying adequate cash to cover non-expense cash outlays. Power
6 Revenue Requirement Study, BP-14-FS-BPA-02, section 3.3.

7 8 **1.2 Statutory and Legal Overview**

9 The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act),
10 16 U.S.C. § 839, is the most prominent statute providing ratemaking directives to BPA.
11 Section 7(a)(1) states:

12 The Administrator shall establish, and periodically review and revise, rates for the
13 sale and disposition of electric energy and capacity and for the transmission of
14 non-Federal power. Such rates shall be established and, as appropriate, revised to
15 recover, in accordance with sound business principles, the costs associated with
16 the acquisition, conservation, and transmission of electric power, including the
17 amortization of the Federal investment in the Federal Columbia River Power
18 System (including irrigation costs required to be repaid out of power revenues)
19 over a reasonable period of years and the other costs and expenses incurred by the
20 Administrator pursuant to this chapter and other provisions of law. Such rates
21 shall be established in accordance with sections 9 and 10 of the Federal Columbia
22 River Transmission System Act (16 U.S.C. § 838) [16 U.S.C. §§ 838g and 838h],
23 section 5 of the Flood Control Act of 1944 [16 U.S.C. § 825s], and the provisions
24 of this chapter.

1 Section 7(a)(1) directs the Administrator to establish, and periodically review and revise, rates
2 for the sale and disposition of electric energy and capacity and for the transmission of
3 non-Federal power. The Northwest Power Act defines “periodically review and revise” as
4 revision of power and transmission rates not less frequently than once in every five years. The
5 section also directs that rates recover all of the Administrator’s costs, including the repayment of
6 the Federal investment in the Federal Columbia River Power System. Rates also are to be set in
7 accord with two other statutes, the Transmission System Act and the Flood Control Act.

8
9 Section 7 directs the allocation of costs, which is performed in a cost of service analysis (see
10 section 2.1 of this Study), and a set of rate directives providing further guidance on how
11 individual rates are to be derived (see section 2.2).

12 13 **1.2.1 Cost of Service Analysis**

14 Northwest Power Act sections 7(b)(1), 7(d), 7(f), and 7(g) provide guidance to BPA for
15 allocating resource and other costs to load (rate) pools. That guidance is summarized below.
16 See section 2.1 for a full discussion of the implementation of these sections of the Northwest
17 Power Act in the Rate Analysis Model (RAM2014).

18
19 Section 7(b)(1) states:

20 The Administrator shall establish a rate or rates of general application for electric
21 power sold to meet the general requirements of public body, cooperative, and
22 Federal agency customers within the Pacific Northwest, and loads of electric
23 utilities under section 5(c) of this title. Such rate or rates shall recover the costs of
24 that portion of the Federal base system resources needed to supply such loads
25 until such sales exceed the Federal base system resources. Thereafter, such rate
26 or rates shall recover the cost of additional electric power as needed to supply

1 such loads, first from the electric power acquired by the Administrator under
2 section 5(c) of this title and then from other resources.

3
4 Section 7(b)(1) describes how BPA is to allocate resource costs to meet the general requirements
5 of public body, cooperative, and Federal agency customers within the Pacific Northwest and
6 loads of electric utilities participating in the Residential Exchange Program (REP) under
7 section 5(c), collectively called the Priority Firm Power (PF) customer class. At this initial stage
8 of the ratesetting process, the PF rate pool consists of the loads of public bodies and cooperatives
9 (collectively identified as preference customers in section 5(b)), which are combined with
10 Federal agency loads in section 7(b)(1), and the loads of the REP participating utilities.

11
12 Section 7(b)(1) instructs that Federal base system (FBS) resources are used to serve the PF rate
13 pool until FBS resources are exhausted. Thus, a corresponding amount of FBS costs is allocated
14 to the PF rate pool. After FBS resources are fully used, resources acquired pursuant to the REP
15 (called exchange resources) are used and then, if needed, new resources are used to serve
16 remaining PF rate load. By allocating resource costs in this order, the appropriate amounts of
17 exchange and new resource costs are allocated to the PF rate pool. The allocation of these costs
18 is discussed in section 2.1.

19
20 Section 7(d)(1) states:

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

1 Section 7(d)(1) thus instructs BPA to apply a Low Density Discount (LDD) to mitigate the costs
2 of customers with relatively fewer customers spread over relatively larger geographic areas. The
3 LDD is discussed in sections 2.1.3.3 and 4.1.1.4.

4
5 Section 7(f) states:

6 Rates for all other firm power sold by the Administrator for use in the Pacific
7 Northwest shall be based upon the cost of the portions of Federal base system
8 resources, purchases of power under section 5(c) of this title and additional
9 resources which, in the determination of the Administrator, are applicable to such
10 sales.

11
12 Section 7(f) sets forth what and how costs are allocated to rates for all other firm power after
13 costs are allocated to the PF rate pool and the rates for BPA's direct-service industrial customers
14 (DSIs) are determined. Section 7(f) allocates the remaining exchange and new resource costs to
15 the remaining regional load (power sold at the New Resources Firm Power (NR) rate and the
16 Firm Power Products and Services (FPS) rate). The allocation of these costs is discussed in
17 section 2.1.

18
19 Section 7(g) states:

20 Except to the extent that the allocation of costs and benefits is governed by
21 provisions of law in effect on December 5, 1980, or by other provisions of this
22 section, the Administrator shall equitably allocate to power rates, in accordance
23 with generally accepted ratemaking principles and the provisions of this chapter,
24 all costs and benefits not otherwise allocated under this section, including, but not
25 limited to, conservation, fish and wildlife measures, uncontrollable events,
26 reserves, the excess costs of experimental resources acquired under section 6 of

1 this title, the cost of credits granted pursuant to section 6 of this title, operating
2 services, and the sale of or inability to sell excess electric power.

3
4 Section 7(g) thus addresses the allocation of costs that are not covered by the previously cited
5 sections of the Northwest Power Act, such as conservation and fish and wildlife costs. The
6 allocation of these costs is discussed in section 2.1.

7 8 **1.2.2 Rate Directives**

9 Northwest Power Act sections 7(c), 7(b)(2), and 7(b)(3) provide further guidance to BPA for
10 ratesetting. Section 2.2 discusses these rate adjustments in detail.

11
12 Section 7(c) in pertinent part states:

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

18
19 Section 7(c) describes how BPA is to set the rate it charges DSI customers. It provides that the
20 DSI rate will be set to be equitable in relation to retail industrial rates of consumer-owned utility
21 (COU) customers. Section 7(c) provides guidance on how to establish and modify this equitable
22 relationship.

23 The [DSI rate] shall be based upon the Administrator's applicable wholesale rates
24 to such public body and cooperative customers and the typical margins included
25 by such public body and cooperative customers in their retail industrial rates but
26 shall take into account the comparative size and character of the loads served, the

1 relative costs of electric capacity, energy, transmission, and related delivery
2 facilities provided and other service provisions, and direct and indirect overhead
3 costs, all as related to the delivery of power to industrial customers, except that
4 the Administrator's rates during such period shall in no event be less than the
5 rates in effect for the contract year ending on June 30, 1985.

6
7 Section 7(c) speaks of the "applicable wholesale rates" to consumer-owned utility (COU)
8 customers plus the "typical margins" included by those customers in their retail industrial rates.
9 These parts of the DSI rate are discussed in section 2.2.2 and Appendix A. Section 7(c) also
10 provides for a comparison of the proposed DSI rate to the DSI rate in effect in 1985, known as
11 the floor rate test. The floor rate test is discussed in section 2.2.2.4. Finally, section 7(c)(3)
12 provides:

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

16
17 Section 7(c)(3) thus directs that the DSI rate is to be adjusted to account for the value of power
18 system reserves provided through contractual rights that allow BPA to restrict portions of the
19 DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. The
20 VOR analysis is discussed in section 3.3.1.1.

21
22 In summary, the result of section 7(c) is that the DSI rate is set equal to the applicable wholesale
23 rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test. Because
24 the DSI rate interacts with the PF rate and the NR rate, the three rates are determined
25 simultaneously through a solution called the 7(c)(2) Delta. The determination and application of
26 the 7(c)(2) Delta are discussed in section 2.2.2.3.

1 Section 7(b)(2) states:

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

10
11 Section 7(b)(2) describes a rate test designed to ensure that preference customers' firm power
12 rates are no higher than rates calculated using five assumptions that remove specified effects of
13 the Northwest Power Act. In settlement of petitions to the U.S. Court of Appeals for the Ninth
14 Circuit challenging BPA's implementation of sections 7(b)(2) and 7(b)(3), the rate test has been
15 implemented through provisions of the 2012 REP Settlement. REP-12-A-03. The 2012 REP
16 Settlement provides a manner by which BPA can compute the amount of rate protection for
17 preference customers, and the amount of REP benefits to the IOUs, in lieu of performing the rate
18 test every rate period.

19
20 Section 7(b)(3) in pertinent part states:

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

24
25 Section 7(b)(3) directs that the cost of any rate protection afforded to preference customers
26 arising from implementation of section 7(b)(2) is borne by all other BPA power sales. The rate

1 protection does not extend to all PF customers: the public body, cooperative, and Federal agency
2 customers receive the rate protection, but REP participants do not. Thus, to allow the cost
3 reallocations due to the rate protection, the PF rate is bifurcated. The two resulting rates are the
4 PF Public rate, which receives the rate protection, and the PF Exchange rate, which does not
5 receive rate protection and bears its allocated share of the rate protection reallocation. The rate
6 protection amount is collected through additional charges included in rates for all non-PF Public
7 sales. The reallocation of rate protection costs is discussed in sections 2.2.1 and 2.2.3.1. The
8 2012 REP Settlement retains the allocation of rate protection costs to all other rates through
9 mechanisms specified therein.

11 **1.2.3 Rate Design**

12 Section 7(e) states:

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

16
17 BPA rates must follow the ratesetting directives of section 7, but, as characterized in the
18 legislative history of the Northwest Power Act, the rate directives govern the amount of revenue
19 the Administrator collects from each class of customers, but not the rate form. See, for example,
20 H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2nd Sess. at 69 (1980). Section 7(e) reserves rate
21 design (how the revenue is collected) to the Administrator. Rate design is discussed in
22 section 2.3.

24 **1.3 Regional Dialogue Policy Overview**

25 In the Long-Term Regional Dialogue Policy (Policy), issued in July 2007, BPA defined its
26 power supply and marketing role for the long term. Key components of the Policy include

1 20-year power sales contracts and a tiered PF rate construct that provides each preference
2 customer with a Contract High Water Mark (CHWM), which defines an amount of power the
3 customer has a right to buy at a Tier 1 rate. Any power a utility chooses to buy from BPA for its
4 load in excess of its CHWM is priced at a Tier 2 rate that is designed to recover the marginal cost
5 of serving this additional load.

6
7 In October 2008, BPA offered contracts to all of its preference customers and investor-owned
8 utilities. By December 5, 2008, all preference customers and three of seven investor-owned
9 utilities (IOUs) signed the new contracts, which went into effect immediately. Power service
10 under these contracts commenced at the start of fiscal year (FY) 2012. The other four investor-
11 owned utilities have since signed.

12
13 In November 2008, BPA issued its Tiered Rate Methodology (TRM) (see section 1.4). Together,
14 the CHWM contracts and the TRM provide long-term certainty to customers regarding their
15 access to Tier 1 rate power and to BPA regarding its obligation to serve its customers' loads.

16 17 **1.3.1 Regional Dialogue Contract Product Descriptions**

18 Below is a brief summary of the products offered under BPA's CHWM contracts. Please refer to
19 BPA's *Regional Dialogue Guidebook*, available in the Regional Dialogue Policy Implementation
20 section of BPA's Web site, www.bpa.gov, for full product descriptions and additional details on
21 the interactions of the products, Tier 2 rate service, and Resource Support Services (RSS).

22
23 **Load Following.** The Load Following product supplies firm power to meet the customer's Total
24 Retail Load (TRL), less any firm power supplied by the customer from any Dedicated Resources,
25 including "behind the meter" non-Federal resource amounts. The costs associated with the

1 energy and capacity necessary to provide the Load Following service are recovered through
2 Tier 1 rate charges for energy and demand.

3
4 **Block.** The Block product provides a planned amount of firm power to meet a customer's
5 planned annual net requirement load. To buy this product, the customer must have dedicated
6 non-Federal resources, and the customer is responsible for using those resources dedicated to its
7 TRL to meet any load in excess of its planned monthly BPA Block purchase. The costs
8 associated with the energy and capacity necessary to provide this service are recovered through
9 Tier 1 rate charges for energy and demand. No customers elected to purchase the Block-only
10 product in the first or second purchase periods. (The purchase periods are defined in the CHWM
11 contracts and also appear in TRM section 4.3.1; the first is FY 2012-2014, and the second is
12 FY 2015-2019.)

13
14 **Slice/Block.** The Slice/Block product provides a combined sale of two distinct power products:
15 (1) firm power for a customer's net requirements load and an advance sale of surplus energy
16 based on the generation shape of the Federal system; and (2) firm requirements power under a
17 Block product. 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 **1.4 Tiered Rate Methodology**

21 The TRM provides for a two-tiered PF Public rate design applicable to firm requirements power
22 service for preference customers that signed a CHWM contract. The TRM establishes a
23 predictable and durable means to calculate BPA's PF tiered rates for power deliveries beginning
24 in FY 2012. The tiered rate design differentiates between the cost of service associated with
25 Tier 1 System Resources and the cost associated with additional amounts of power sold by BPA
26 to serve any remaining portion of a customer's net requirement, also referred to as Above-Rate

1 Period High Water Mark (Above-RHWM) load. The tiering of the PF Public rate is one of the
2 final steps in the development of rates and does not alter the fundamental manner in which BPA
3 allocates costs to the various rate pools under the Northwest Power Act. Section 2.3.2 describes
4 the steps taken to tier the Priority Firm rates.

5
6 CHWMs, determined according to the TRM, are one basis (others are described later in this
7 section) for determining how much of each customer's net requirement purchased from BPA is
8 charged at Tier 1 rates and how much may be charged at Tier 2 rates. The CHWM for each
9 customer was calculated by BPA in FY 2011 based on the expected output of Tier 1 system
10 resources during FY 2012–2013 and customers' actual FY 2010 loads to set each customer's
11 initial eligibility to purchase power at Tier 1 rates. The individual utility CHWMs were added to
12 each utility's CHWM contract.

13
14 Related to the CHWM is the RHWM, which is an expression of the CHWM scaled to the
15 expected output of resources identified as comprising the Tier 1 system for the relevant rate
16 period. Each customer's RHWM for FY 2014–2015 defines that customer's maximum
17 eligibility to purchase at Tier 1 rates for the rate period, limited for Slice and Block customers by
18 the purchaser's Annual Net Requirement and for Load-Following customers by the purchaser's
19 Actual Net Requirement. Each customer's RHWM for FY 2014–2015 was established in a
20 public process that preceded the start of this rate proceeding. The TRM specifies how rates will
21 be developed that ensure, to the maximum extent possible, that customers' purchases of power at
22 Tier 1 rates do not pay any of the costs of serving Above-RHWM load.

23
24 To meet its Above-RHWM load, a customer may purchase Federal power, non-Federal power, or
25 a combination of the two. To the extent a customer purchases Federal power for its Above-
26 RHWM load, a PF Tier 2 rate(s) will be applied to this portion of its Federal power service.

1 **1.5 Rate Options Supporting Regional Dialogue Products**

2 **1.5.1 Above-RHWM Load Service**

3 A customer may choose to have its Above-RHWM load served as net requirements load by BPA
4 at Tier 2 rates, consistent with the appropriate contractual notice and commitment requirements,
5 which are summarized in the TRM. The Tier 2 rate alternatives currently available are the Tier 2
6 Load Growth rate, the Tier 2 Short-Term rate, and a Tier 2 Vintage 2014 rate for FY 2015–2019.
7 Additional Tier 2 Vintage rates may be offered in future rate periods. Additional information on
8 the Tier 2 rate alternatives can be found in BPA’s *Regional Dialogue Guidebook*. A description
9 of rates for Tier 2 service can be found in Study section 3.1 and in the PF-14 rate schedule.

10
11 Alternatively, a customer may add its own non-Federal resources to serve all or part of its
12 Above-RHWM load. The notice and commitment periods for non-Federal resources or
13 purchases are identical to those for purchases from BPA at the Tier 2 Short-Term rate, as
14 specified in the CHWM contract.

15
16 **1.5.2 Resource Support Services**

17 BPA has developed a suite of Resource Support Services (RSS) and related services for
18 customers’ non-Federal resources. These services are priced at Tier 2 rates and include Diurnal
19 Flattening Service (DFS), Forced Outage Reserve Service (FORS), Secondary Crediting Service
20 (SCS), Resource Remarketing Service (RRS), and Transmission Curtailment Management
21 Service (TCMS). Depending on the type of resource and its output, RSS may be required to be
22 purchased from either BPA or non-Federal sources for purposes of matching the resource to a
23 planned shape and amount of load. These services enable BPA to cover the costs of following
24 the variation between planned and actual customer resource amounts and to account for the
25 impact that resource shapes and fluctuations have on BPA’s cost to meet its customers’ net
26 requirement load. Additional information on the RSS suite of products can be found in Study

1 section 3.1.1.3, BPA’s *Regional Dialogue Guidebook*, and the General Rate Schedule Provisions
2 (GRSPs), BP-14-A-03-AP01.

3 4 **1.6 Rate Period High Water Marks**

5 Each customer’s RHW M helps to define that customer’s maximum eligibility to purchase power
6 at PF Tier 1 rates for the rate period. The RHW M is determined based on the customer’s
7 CHW M and the RHW M Tier 1 System Capability (RT1SC) for each applicable rate period. The
8 determination of a customer’s RHW M occurs outside of the rate proceeding in the RHW M
9 Process, as described in TRM section 4.2.1.

10
11 The RHW M Process for the FY 2014–2015 rate period was completed in September 2012. BPA
12 completed the Tier 1 System Firm Critical Output Study in May 2012, posted draft RHW Ms in
13 June, and conducted a collaborative review process through early August. BPA then posted
14 initial RHW Ms on August 9, 2012, conducted a public meeting, and provided a formal public
15 comment period. After completion of the review and comment period, BPA examined the
16 information collected and posted its determination of values for the FY 2014–2015 rate period
17 for RHW M Tier 1 System Capability, including RHW M Augmentation, the monthly/diurnal
18 shape of RHW M Tier 1 System Capability, each customer’s RHW M, each customer’s Forecast
19 Net Requirement, and each customer’s Above-RHW M Load.

20
21 The RHW Ms and related outputs of the RHW M Process are combined with the load forecast for
22 the applicable 7(i) proceeding to calculate billing determinants. Billing determinants affected by
23 the RHW Ms include (1) a forecast of power sold at Load Shaping Rates; (2) the Tier 1 Cost
24 Allocators (TOCAs); and (3) Demand. Additionally, RHW M outputs affect the amount of
25 Unused RHW M to compensate the Composite and Non-Slice cost pools for any value difference
26 between an unused share of the Tier 1 system and the value of a flat annual block of power

1 associated with unneeded system augmentation due to the amount of Unused RHW. For a
2 description of how values calculated in the RHW Process are used in the calculation of billing
3 determinants, see section 3.1.5.

4
5 Once established, RHWs are, under most circumstances, not changed. Exceptions include
6 certain changes on a customer's system: annexation; gaining or losing service territory; later
7 discovery that a load is a new large single load; and loss of Provisional CHW. Provisional
8 CHW for a customer is an amount of load that a customer lost prior to FY 2010, the year
9 established as the basis for computing CHWs, and the customer had reason to believe would
10 return before FY 2014. When CHWs were being established, each customer that met
11 TRM-specified criteria could request Provisional CHW. If BPA determined that the criteria
12 were met, the Provisional CHW was granted and the customer's CHW for FY 2012-2013
13 was increased. The RHW Process preceding the BP-14 rate proceeding established an RHW
14 for each customer assuming that its Provisional CHW would be retained.

15
16 Section 1.1.1 of Exhibit B of the CHW contracts specifies that:

17 This Provisional CHW Amount will only be retained if the retention conditions,
18 specified in section 4.1.8 of the TRM, are achieved. BPA shall determine the
19 amount, if any, of «Customer Name»'s Provisional CHW Amount to be
20 retained. By September 15, 2014, BPA shall revise the table above to include
21 «Customer Name»'s permanent CHW. «Customer Name»'s permanent
22 CHW will be effective retroactively to October 1, 2013.

23
24 There are 41 customers with a total of 80.617 aMW in Provisional CHW amounts. During
25 FY 2014, BPA will review the Provisional CHW amounts using TRM section 4.1.8 to
26 determine how much of the Provisional CHW amount each customer retains. To the extent

1 the customer meets the TRM criteria, its Provisional CHWM amount will become permanent
2 CHWM. To the extent that the customer does not meet the TRM criteria, its Provisional CHWM
3 amount will be removed.

4
5 The removal of all or part of a customer's Provisional CHWM amount necessitates a
6 recomputation of the customer's RHWMM and Above-RHWMM load for FY 2014-2015. The
7 quantity of RHWMM lost is reflected as an increase in Above-RHWMM load. The retention of all or
8 part of a customer's Provisional CHWM amount necessitates a recomputation of the customer's
9 Contract Demand Quantity (CDQ); CDQs were not adjusted to reflect Provisional CHWM
10 amounts when the provisional amounts were established.

11
12 If a customer's RHWMM is reduced during FY 2014 due to loss of a Provisional CHWM amount,
13 the TRM specifies that the customer's BPA power bills, beginning with its October 2013 bill,
14 will be adjusted to reflect the revised RHWMM. The reduction in RHWMM will be translated into a
15 revised TOCA that will be lower than used on the power bills, and the customer's Tier 1 billing
16 will be reduced. At the same time, the reduction in RHWMM will be translated into a revised
17 Above-RHWMM load that is larger than before. TRM section 4.1.10 specifies that the customer
18 shall be billed at Load Shaping rates for the increase in Above-RHWMM load in FY 2014.

19 Depending on product choices and service elections, customers may have different requirements
20 for FY 2015. See TRM section 4.1.10. The TRM provisions for adjusting a customer's TOCA
21 and rebilling are incorporated in GRSP II.Y.

22
23 If any portion of a customer's Provisional CHWM amount is made permanent, the TRM
24 specifies that the customer's CDQ is revised and power bills, beginning with its October 2011
25 bill, will be adjusted to reflect the revised CDQ. The billing is retroactive to October 2011
26 because the demand charges the customer paid during FY 2012-2013 did not reflect the higher

1 CDQ the customer would have received if the Provisional CHWM amount had been permanent
2 CHWM during those years. Thus, any CDQ revision will lead to a refund of demand charges to
3 the customer; a customer will not owe BPA more money for the demand adjustment. The TRM
4 provisions for adjusting a customer's demand billing determinants for a CDQ revision and
5 rebilling are incorporated in GRSP II.D.3.

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1 **2.1.1 Cost of Service Analysis Modeling**

2 The COSA modeling uses disaggregated customer load data from the source data used to
3 produce the Power Loads and Resources Study, BP-14-FS-BPA-03. See PRS Documentation
4 Table 2.1.1. The disaggregated load data are aggregated into the PF rate pool (consisting of two
5 sub-pools, the PF Public (PFp) rate pool and the PF Exchange (PFx) rate pool); the Industrial
6 Firm Power (IP) rate pool; the NR rate pool; and the FPS rate pool. See Documentation
7 Table 2.2.2. The rates charged for service to the various rate pools are associated with specific
8 sections in the Northwest Power Act that describe how costs are to be allocated to those rate
9 pools: the PF rates are section 7(b) rates; the IP rates are section 7(c) rates; and the NR and FPS
10 rates are section 7(f) rates. See section 1.2.

11
12 After the load data is input into the RAM2014, the COSA modeling uses the disaggregated
13 resource data from the source data in the Power Loads and Resources Study. See Documentation
14 Table 2.1.2. The disaggregated resource data are aggregated into the resource pools specified by
15 section 7 of the Northwest Power Act. These resource pools are the FBS resource pool, the
16 exchange resource pool, and the new resource pool. See Documentation Table 2.2.2. The
17 resources in the FBS and new resource pools are actual or planned resources that will be able to
18 serve actual load during the rate period. The exchange resources are sized to be equal to the
19 forecast of the eligible REP exchange load during the rate period. To calculate the eligible REP
20 exchange load, the COSA modeling includes a test that determines whether the potential
21 exchanging utilities have Average System Costs (ASC) that are greater than the applicable Base
22 PFX rate for the rate period. See section 2.2.1. Those utilities with higher ASCs will be
23 participating in the REP during the rate period. See Documentation Table 2.1.3. In this way, the
24 modeling determines the PFX load, the size of the exchange resource pool, and the costs of the
25 exchange resources (the ASCs multiplied by the eligible exchange loads).

1 The aggregated load and resource data is used to calculate energy allocation factors (EAFs) that
2 the COSA modeling will use to apportion costs among rate pools. In order to properly calculate
3 EAFs, loads and resources must equal one another; the RAM2014 tests to ensure that this load-
4 resource balance exists. The EAFs are calculated based on the priorities of service from resource
5 pools to rate pools specified in section 7 of the Northwest Power Act, and based on general
6 principles of cost causation when section 7 does not provide guidance. Section 7(b)(1) directs
7 BPA to allocate the cost of the FBS resources to the PF load pool first. When the FBS resources
8 are not sufficient to serve all PFp and PFX loads, section 7(b)(1) directs BPA to serve the
9 remaining load, first with resources obtained by BPA under section 5(c) of the Northwest Power
10 Act—that is, the exchange resources—and then with new resources, as needed. In this proposal,
11 all of the FBS and a large portion of exchange resources are needed to serve PF loads, and no
12 new resources are needed. After all of the FBS resource costs and the portion of the exchange
13 resource costs are allocated to the PF rate pool, section 7(f) of the Act directs BPA to allocate the
14 cost of the remaining exchange resources and the cost of any other resources, new resources, to
15 all remaining load.

16
17 The COSA modeling uses revenue requirement cost data from the Power Revenue Requirement
18 Study. See Documentation Table 2.3.1. The disaggregated cost data is aggregated into BPA’s
19 ratemaking cost pools specified by section 7 of the Northwest Power Act. See Documentation
20 Table 2.3.2. Sections 7(b) and 7(f) describe how costs associated with resource pools (FBS
21 costs, exchange resource costs, and new resource costs) are to be allocated to load/rate pools.
22 Section 7(g) describes how the costs associated with the other cost pools (conservation costs,
23 BPA program costs, power-related transmission costs) are to be allocated to load/rate pools.

24
25 Functionalization of costs between the generation and transmission functions (BPA does not
26 have a distribution function normal to most utilities) is performed in the Power Revenue

1 Requirement Study and the Transmission Revenue Requirement Study. The costs functionalized
2 to the generation function are included in the power revenue requirement found in the COSA
3 modeling (one exception to this is exchange resource costs; see section 2.1.3.2). As stated
4 above, the exchange resource costs are calculated internal to the RAM2014. The exchange
5 resource costs include transmission function costs. The exchange resource costs are
6 functionalized in the COSA modeling so that only the generation portion of the exchange
7 resource costs is subject to the power cost rate steps, and the transmission cost portion is then
8 added back in after the Rate Directives Step is completed. See Documentation Table 2.3.4.2.
9 In this way, the statutorily mandated power cost relationships between the various rate pools
10 are maintained without being affected by the exchange transmission function costs.

11
12 The COSA modeling uses other costs in addition to exchange resource costs that are internally
13 generated by the RAM2014. These include some power purchase costs, revenue shortfall costs
14 associated with some rate credits, and revenues from secondary power sales. These items will be
15 covered in greater detail below.

16
17 In addition to cost data, the COSA modeling receives input data associated with various revenue
18 credits. Some of these revenue credits are associated with the operation of FBS resources and
19 have the effect of reducing the FBS resource costs to be recovered by power rates. There are
20 also revenue credits that have the effect of reducing the new resource and conservation costs.
21 Some revenue credits that are not associated with any particular cost pool are allocated to all rate
22 pools on a pro rata load basis. See Documentation Table 2.3.6.

23
24 The COSA modeling concludes by using the calculated EAFs to allocate the costs and credits to
25 the rate pools. One further adjustment to the allocated costs is necessary because the costs
26 allocated to the FPS rate pool will not be equal to the expected revenues from FPS contract sales.

1 Therefore, an FPS surplus/deficiency adjustment to the COSA allocated costs is performed
2 before the calculation of initial power rates. See Documentation Table 2.3.9. The initial power
3 rates resulting from the COSA Step are the starting point for the Rate Directives Step modeling
4 in the RAM2014. See Documentation Table 2.3.10.

5
6 Sections 2.1.2, 2.1.3, and 2.1.4 provide more detailed explanations to the material summarized
7 here.

8 9 **2.1.2 Loads and Resources**

10 The sizes of the rate and resource pools are determined based on the results of the Power Loads
11 and Resources Study. The process of allocating power costs begins with an examination of
12 critical period firm loads and resources. After certain adjustments are made, RAM2014
13 calculates a ratemaking load-resource balance for each year of the rate period. From this
14 ratemaking load-resource balance, RAM2014 determines service to each of the four rate pools
15 (PF, NR, IP, and FPS) from each of the three resource pools (FBS, exchange, and new resources)
16 for the rate period.

17
18 The Power Loads and Resources Study distinguishes between PFp load to be served at a Tier 1
19 price and PFp load that is subject to Tier 2 pricing. The analogous distinction also holds for
20 resources: the Power Loads and Resources Study identifies Tier 1 system resources and
21 resources whose costs will be assigned to Tier 2 cost pools. Notwithstanding this distinction in
22 the input data, the COSA allocations are performed with the tiered loads aggregated as a single
23 PFp load and the newly purchased resources combined into one FBS resource pool. The one
24 exception to this combining of tiered inputs in the COSA calculations is in the calculation of the
25 COU Base PFx rate. This exception is made in order to reflect the CHWM contractual
26 requirement that the COU Base PFx rate, as used to establish whether a COU is eligible to

1 participate in the REP, excludes all Tier 2 resource costs and any Tier 2 loads in its calculation.
2 See Documentation Table 2.4.8. Documentation Table 2.2.1 shows the ratemaking energy loads
3 and resources by pools.
4

5 The REP, created by section 5(c) of the Northwest Power Act, was designed to provide
6 residential and small farm customers of Pacific Northwest utilities a form of access to low-cost
7 Federal power. Under the REP, BPA purchases power (exchange resources) from each
8 participating utility at that utility's ASC. BPA establishes a utility's ASC through a formal ASC
9 Review Process. Once a utility's ASC is established, BPA offers, in exchange, to sell an
10 equivalent amount of electric power (exchange loads) to the utility at BPA's PFX rate. The
11 exchange actually transfers no power to or from BPA, because the "exchange" is an accounting
12 transaction in which dollars are exchanged rather than electric power. However, to ensure proper
13 cost allocations and rate determinations, RAM2014 models the REP as a purchase of power by
14 BPA (priced at the participants' ASCs) and a simultaneous sale of power to the REP participants
15 (priced at the participants' PF Exchange rates).
16

17 **2.1.2.1 Load and Resource Adjustments**

18 The Power Loads and Resources Study includes a forecast of the generation capability of all
19 resources available to BPA to serve all its load obligations. In order to produce a power
20 ratemaking load-resource balance that includes the amount of resource available to serve the rate
21 pool loads, some adjustments must be made. BPA has certain system obligations, including the
22 Canadian Entitlement, the Hungry Horse reservation, and U.S. Bureau of Reclamation (USBR)
23 Pumping loads (together called FBS obligations), that have existed since before the passage of
24 the Northwest Power Act. FBS resources used to serve these system obligations are "taken off
25 the top," removing both the obligation and a corresponding amount of FBS resource before the
26 ratemaking load-resource balance is calculated.

1 Similarly, there is an amount of the FBS used to serve a group of power contracts that enhances
2 the amount of FBS available to serve the ratemaking rate pools. These contracts take the form of
3 either a capacity-energy exchange or a seasonal exchange. Each of these types of exchanges is a
4 “sale” of power that is paid for by returning more power than is delivered. In ratemaking, the
5 deliveries and the equivalent returns are removed from consideration, and the energy payment is
6 included in the FBS, increasing the net size of the FBS with power at no added cost. The
7 ratemaking load-resource balance after adjustments is shown in Documentation Table 2.2.2.

9 **2.1.2.2 Load Pools**

10 Load pools (also called rate pools) are groupings of forecast sales into customer classes for cost
11 allocation purposes. The Northwest Power Act establishes three rate pools based on the loads
12 served at particular rates. The 7(b) rate pool includes sales to public body and cooperative
13 customers (consumer-owned utilities), Federal agencies, and utilities participating in the REP.
14 The 7(c) rate pool includes sales to BPA’s direct-service industrial customers under contracts
15 authorized by section 5(d) of the Northwest Power Act. The 7(f) rate pool includes three
16 groupings: (1) power sold to consumer-owned utilities that is determined to serve new large
17 single loads; (2) section 5(b) requirements power sold to the region’s investor-owned utilities;
18 and (3) all power BPA sells pursuant to section 5(f) of the Northwest Power Act.

19
20 The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any
21 resource costs to the IP rate pool; rather, the IP rate is a formulaic rate established pursuant to
22 section 7(c). However, if DSI loads were excluded from cost allocations, loads and resources
23 would be out of balance, leaving an amount of resource costs not allocated to any loads.

24 Therefore, BPA allocates resource costs to IP loads as it does to all other remaining (*i.e.*, non-PF)
25 firm power sold. Thus, beginning in 1985 with the implementation of the directives of
26 section 7(c)(1)(b) of the Northwest Power Act, BPA has had, for all practical purposes, only

1 two rate pools, the 7(b) rate pool and all other loads. The resource cost allocations to the IP rate
2 pool are adjusted later in the Rate Directives Step to conform the IP rate to its formulaic basis.

3 4 **2.1.2.3 Resource Pools**

5 The three resource pools are Federal base system resources, exchange resources, and new
6 resources.

7
8 Defined in section 3(10) of the Northwest Power Act, the FBS resource pool consists of the costs
9 of the following resources: (1) the Federal Columbia River Power System (FCRPS) hydroelectric
10 projects; (2) resources acquired by the Administrator under long-term contracts in force on the
11 effective date of the Northwest Power Act; and (3) replacements for reductions in the capability
12 of the above resources. Market purchases of system augmentation, balancing purchases, and
13 purchases designated for Tier 2 rate purposes have been included in the FBS as replacements for
14 reductions in the capability of FBS resources. Costs expected to be incurred during the rate
15 period for FBS replacement resources are included in the FBS resource cost pool.

16
17 Exchange resources are set equal to the amount of qualifying exchange load, which implements
18 the direction in section 5(c)(1) that BPA is to purchase resources from each eligible REP
19 participant and sell an equivalent amount of electric power to each participant.

20
21 Finally, the new resources pool includes all other resources acquired by BPA, unless such
22 resource has been determined to be a replacement of reduced FBS capability.

23 24 **2.1.2.4 Order of Resource Service to Load Pools**

25 As noted in section 2.1.1, section 7(b)(1) of the Northwest Power Act specifies how resource
26 costs must be allocated to the Priority Firm Power customer class. FBS resources are used to

1 serve the PF rate pool until FBS resources are exhausted, whereupon exchange resources and
2 then new resources are used to serve remaining PF rate load. Section 7(f) of the Northwest
3 Power Act specifies what and how costs are allocated to “all other firm power” after costs are
4 allocated to the PF rate pool: the remaining exchange and new resources costs are allocated to
5 remaining load. That remaining load is Industrial Firm Power, New Resource Firm Power, and
6 Firm Power Products and Services contracts.

7
8 For the BP-14 rates, the PF load (which at this point consists both of PFp and PFx loads) is
9 greater than the capability of the FBS resources. Therefore, all FBS costs and benefits are
10 allocated to the PF rate pool. Because the remaining PF load is less than the total exchange
11 resource under section 5(c), a pro rata share of exchange resource costs is allocated to the PF rate
12 pool in the amount necessary for the exchange resource to serve the PF load not served by FBS
13 resources. The remaining exchange resources and all new resources and their attendant costs are
14 allocated to all other firm load.

16 **2.1.2.5 Energy Allocation Factors**

17 Energy allocation factors are calculated for each resource pool–rate pool combination by
18 dividing the amount of annual energy load in each rate pool served from each resource pool. The
19 annual EAFs for each resource cost pool and for the rate directive steps are shown in
20 Documentation Table 2.2.3. The Total Usage and Conservation allocation factors assume a
21 pro rata allocation of costs to all firm loads. For example, the Total Usage EAF for costs
22 allocated to the PF load pool is equal to the ratio of PF load to total firm load. The Total Usage
23 and Conservation EAFs are used to allocate some section 7(g) costs and rate directive allocation
24 adjustments to all firm energy loads.

1 **2.1.3 Ratemaking Costs**

2 For ratemaking purposes BPA’s costs are allocated to six cost pools. The first three cost pools
3 are associated with BPA’s resource pools: FBS costs, exchange resource costs, and new resource
4 costs. These resource-related costs are allocated in accordance with sections 7(b)(1) and 7(f) of
5 the Northwest Power Act. The other three cost pools—conservation costs, BPA program costs,
6 and power-related transmission costs—are allocated in accordance with section 7(g). The PF
7 revenue requirement also is adjusted upward due to the expected revenue shortfall caused by the
8 implementation of the Low Density Discount and the Irrigation Rate Discount. See
9 sections 2.1.3.3 and 2.1.3.4.

10
11 **2.1.3.1 Revenue Requirement**

12 The Bonneville Project Act, the Flood Control Act of 1944, the Transmission System Act, and
13 the Northwest Power Act provide guidance regarding BPA ratemaking. The Northwest Power
14 Act and the other statutes, using similar language, require BPA to set rates that are sufficient to
15 recover, in accordance with sound business principles, the costs of acquiring, conserving, and
16 transmitting electric power, including amortization of the Federal investment in the FCRPS over
17 a reasonable period of years, and the other costs and expenses incurred by the Administrator.
18 See section 1.2.

19
20 The Power Revenue Requirement Study is based on power revenue and cost estimates for a
21 two-year rate period, FY 2014-2015. A preliminary generation revenue requirement from the
22 Power Revenue Requirement Study is supplemented in the COSA for costs that are determined
23 in other steps of the ratemaking process: projected balancing purchase power costs; system
24 augmentation costs; Planned Net Revenues for Risk (PNRR), if any; and the functionalized
25 exchange resource costs. The annual revenue requirements used for rate calculations are shown
26 in Documentation Table 2.3.2. Disaggregated costs are listed in a form consistent with the
27 income statement from the Power Revenue Requirement Study and are shown in Documentation

1 Table 2.3.1. RAM2014 uses key code mapping to allocate all costs to the COSA cost pools and
2 the TRM cost pools. Because of the different purposes of the COSA and the TRM, the COSA
3 cost pools do not match the TRM cost pools; however, all costs appear in both sets of cost pools.
4

5 Three categories of purchased power are included in the COSA: (1) purchased power, (2) system
6 augmentation, and (3) balancing power purchases.
7

8 **Purchased Power.** The purchased power subset of purchased power costs includes the costs of
9 acquisition of power through renewable energy, wind, geothermal, and competitive acquisition
10 programs. Costs of purchased power are included in the new resources pool.
11

12 **System Augmentation.** For ratesetting purposes, it is assumed that BPA acquires resources
13 beyond the inventory represented by the system generating resources and balancing power
14 purchases. These system augmentation acquisition amounts are determined in the Power Loads
15 and Resources Study and are used to meet annual customer firm power loads in excess of annual
16 firm system resources. The mean price from the Critical Water Run is used to value the cost of
17 system augmentation. Power Risk and Market Price Study, BP-14-FS-BPA-04. System
18 augmentation purchases are treated as FBS replacements, and as such, the costs are included in
19 and allocated as FBS costs. See Documentation Tables 2.3.1 and 2.3.2.
20

21 **Balancing Power Purchases.** The costs of power purchases and storage required to meet firm
22 deficits on a monthly/diurnal basis are included in the category of balancing power purchases.
23 Projected balancing power purchases are generally needed to serve firm loads in months other
24 than the spring fish migration period under some water conditions. Balancing purchase expenses
25 are calculated for each monthly/diurnal period where BPA is deficit energy across all 3,200
26 iterations in RevSim. The median purchasing price and quantity associated with these purchases

1 for each year of the rate period are passed to RAM2014 to compute balancing purchase costs.
2 Power Risk and Market Price Study Documentation, BP-14-FS-BPA-04A, Tables 18 and 19.
3 Balancing power purchases are treated as FBS replacements, and as such, the costs are included
4 in and allocated as FBS costs. See Documentation Tables 2.3.1 and 2.3.2.

6 **2.1.3.2 Functionalization of Exchange Resource Costs**

7 In the COSA, exchange resource costs are based on participating utilities' ASCs and their
8 exchange power sales to BPA. Each utility's ASC includes the cost of power and transmission
9 services associated with serving that utility's total retail load. By definition, exchange resource
10 sales to BPA equal the exchange sales by BPA. The rate directive adjustments that occur
11 subsequent to the COSA use the results of the COSA allocations of the generation revenue
12 requirement. Therefore, because the exchange resource costs in the COSA include transmission
13 costs, the PF Exchange rate includes a transmission cost adder, and the exchange resource costs
14 are functionalized between power and transmission. The exchange resource costs functionalized
15 to power continue through the ratemaking process. The exchange resource costs functionalized
16 to transmission are removed from the generation revenue requirement for the Rate Directives
17 Step and are added back to determine the PF Exchange rate after the Rate Directives Step is
18 completed. In this way, the exchange resource costs functionalized to power are treated the same
19 as other power function costs through the rate development process. The transmission function
20 costs are collected directly from PFx loads through a transmission adder included in the PFx rate.
21 Because the amount of exchange resource costs functionalized to transmission is equal to the
22 increased revenue due to the PFx rate adder, there is no net cost of these transmission costs to
23 other rates. The functionalization of exchange resource costs is shown in Documentation
24 Table 2.3.4.2.

1 **2.1.3.3 Low Density Discount**

2 Section 7(d)(1) of the Northwest Power Act provides that, in order to avoid adverse impacts on
3 retail rates of BPA’s customers with low system densities, BPA shall apply, to the extent
4 appropriate, discounts to the rate or rates for such customers.

5
6 The cost of providing the discount is computed in RAM2014 using offset quantities and the
7 internally computed TRM rates. Offset quantities are the sum of the applicable LDD
8 percentages applied to the customer-specific billing determinants. These offsets are computed in
9 the TRM Billing Determinants Model, which is a module of RAM2014.

10
11 The estimated cost of the LDD is shown in Documentation Table 2.3.3. The entire cost of the
12 discount is allocated to the PF load pool prior to linking the IP rate to the PF rate.

13
14 **2.1.3.4 Irrigation Rate Discount**

15 A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and the
16 TRM. The discount is a rate, expressed in mills per kilowatt-hour, that when applied to qualified
17 irrigation load, produces a dollar credit on eligible customer power bills. The Irrigation Rate
18 Discount rate is calculated in RAM2014, as described in section 3.1.11.1. The cost of the
19 discount is computed in RAM2014 using contract irrigation loads and the internally calculated
20 rate. The entire cost of the IRD is allocated to the PF load pool prior to linking the IP rate to the
21 PF rate.

22
23 **2.1.3.5 Cost Pools**

24 The COSA has six cost pools for the initial allocation of BPA’s power costs: FBS resource costs,
25 exchange resource costs, new resource costs, conservation costs, BPA program costs, and power
26 transmission costs. These costs are allocated to the various customer load classes using direction
27 from sections 7(b)(1), 7(f), and 7(g) of the Northwest Power Act.

1 **2.1.3.5.1 Section 7(b)(1) costs**

2 Section 7(b)(1) costs are associated with the resource cost pools necessary to serve PF load,
3 including the PFp load and the PFx load. For the BP-14 rates, these resources are all of the FBS
4 resources and a large portion of the exchange resources. Therefore, all FBS resource costs and
5 most of the exchange resource costs are section 7(b)(1) costs allocated to serve section 7(b)(1)
6 loads; that is, PF loads.

7
8 **2.1.3.5.2 Section 7(f) Costs**

9 Section 7(f) costs are associated with the resource cost pools necessary to serve non-PF load,
10 including IP, NR, and FPS loads. For the BP-14 rates, these resources are a small portion of the
11 exchange resources and all of the new resources. Therefore, a small portion of exchange
12 resource costs and all new resource costs are section 7(f) costs allocated to serve all remaining
13 loads; that is, IP, NR, and FPS loads.

14
15 **2.1.3.5.3 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 serve
18 loads. The “conservation” line item, as seen in Documentation Tables 2.3.1 and 2.3.2, includes
19 (1) amortization of BPA’s previous conservation resource acquisition activities; (2) BPA’s
20 continuing contributions to the region’s market transformation efforts; (3) costs associated with
21 BPA’s energy efficiency business; and (4) a share of Net Revenues (Minimum Required Net
22 Revenues (MRNR) plus PNRR, if any). See Documentation Table 2.3.7.4. Conservation costs
23 are allocated to all rate pools using the Conservation EAFs. See Documentation Table 2.3.4.3.

24
25 **BPA Program Costs.** Some of BPA’s program costs are not identified directly with any
26 specific resource pool. An example is the cost of tracking and implementing national energy
27 policies and initiatives. Development of these power program costs occurs in the Integrated

1 Program Review, as described in Power Revenue Requirement Study section 2.1. The power
2 portion appears in the COSA as BPA program costs. BPA program costs are allocated to all rate
3 pools based on the Total Usage EAFs. See Documentation Table 2.3.4.3.

4
5 **BPA Power Transmission Costs.** Power transmission expenses include the costs of serving
6 transfer service customers with Federal power wheeled under GTAs and other non-Federal
7 transmission service agreements over a third-party transmission system. It also includes the
8 costs Power Services incurs to procure transmission and ancillary services to transmit surplus
9 Federal power to purchasers that do not hold transmission contracts, primarily outside the Pacific
10 Northwest. Finally, it includes the costs of the generation-integration segment, as determined in
11 the transmission segmentation study. Transmission costs are allocated to all rate pools based on
12 the Total Usage EAFs. See Documentation Table 2.3.4.3.

13 14 **2.1.3.6 Planned Net Revenues for Risk**

15 PNRR is an amount of net revenues required from power rates to ensure that cash flows from
16 proposed rates meet BPA's probability standard for repaying Power Services' portion of
17 Treasury payments on time and in full. PNRR may also include an amount of cash required to
18 restore an accumulated negative balance of financial reserves attributed to Power Services.
19 Under the ratemaking methodology, the amount of PNRR is the result of an iterative process
20 among several models: RAM2014, RevSim, Non-Operating Risk Model (NORM), and ToolKit.
21 See Power Risk and Market Price Study section 3.3. The iteration is initiated with a seed value
22 for PNRR in Documentation Tables 2.3.1 and 2.3.2. The resultant rates are used in RevSim to
23 produce net revenue probability distributions. These net revenue distributions are then used in
24 the ToolKit to produce a new PNRR value. See Documentation Table 2.3.1. Because the PNRR
25 is zero for the BP-14 rates, no iterative process is required to determine rate levels.

1 **2.1.4 Revenue Credits**

2 **2.1.4.1 Downstream Benefits and Pumping Power Revenues**

3 Downstream benefits and pumping power revenues are described in section 4.2. Downstream
4 benefits and pumping power revenues are associated with FBS resources, and these credits are
5 allocated to loads that have been allocated the costs of the FBS. See Documentation Table 2.3.6.

6
7 **2.1.4.2 Section 4(h)(10)(C) Credits**

8 Section 4(h)(10)(C) credits are described in section 4.4.1. The forecast credit is calculated as
9 described in Power Risk and Market Price Study section 2.6.1 and supplied to RAM2014.

10 Section 4(h)(10)(C) credits are associated with FBS resources, and these credits are allocated to
11 loads that have been allocated the costs of the FBS. See Documentation Table 2.3.6.

12
13 **2.1.4.3 FBS Contract Obligations Revenue**

14 BPA has certain FBS system obligations that provide revenues. These include the pre-
15 Subscription Hungry Horse reservation power sales contracts and some seasonal exchanges.
16 These FBS system obligation revenues are associated with FBS resources and are allocated to
17 loads that have been allocated the costs of the FBS. See Documentation Table 2.3.6.

18
19 **2.1.4.4 Colville Credit**

20 The Colville credit is described in section 4.4.2. The Colville credit is associated with FBS
21 resources, and this credit is allocated to loads that have been allocated the costs of the FBS.
22 See Documentation Table 2.3.6.

23
24 **2.1.4.5 Energy Efficiency Revenues**

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

1 expenditures that are included in the generation revenue requirement. The Energy Efficiency
2 revenue credit is allocated in the same way as BPA's conservation expenses and effectively
3 reduces the amount of those expenses allocated to power rates. See Documentation Table 2.3.6.
4

5 **2.1.4.6 Miscellaneous Revenues**

6 Miscellaneous revenues are described in section 4.1.8. These revenues are allocated to all firm
7 load through the General Cost EAFs. See Documentation Table 2.3.6.
8

9 **2.1.4.7 Renewable Energy Certificates**

10 Revenues result from BPA's sales of Renewable Energy Certificates (RECs). The revenue is
11 based on BPA's established price for RECs of \$10.25 for FY 2014 and \$15.00 for FY 2015 and
12 renewable project output included in the FBS and new resources resource pools. The revenues
13 from Klondike III RECs are allocated to loads that have been allocated the costs of the FBS, and
14 the revenues from new resources renewable resource RECs are allocated to loads that have been
15 allocated the costs of the new resources. See Documentation Table 2.3.6.
16

17 **2.1.4.8 General Revenue Credits**

18 In the course of marketing power, Power Services generates transmission-related revenues and
19 credits. The revenues and credits are predominantly revenues associated with providing reserves
20 and energy for ancillary services, control area services, and other reliability needs. The
21 Generation Inputs Study explains and documents these credits. Revenues associated with
22 Generation Inputs, Network Wind Shaping, and RSS for non-Federal resources are allocated to
23 all loads through the General Cost EAFs. See Documentation Tables 2.3.7.5 and 2.3.7.6.
24
25
26

1 **2.1.4.9 Secondary Revenue Credits**

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

5
6 The ratemaking process described above ensures that the forecast of firm resources available to
7 serve load is equal to BPA’s firm load obligations under critical water conditions. However, the
8 ratesetting process also recognizes that better than critical water conditions will most likely
9 occur. Generation from water in excess of critical water conditions is called secondary energy.

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

13
14 The sales of energy in excess of firm obligations on a monthly/diurnal basis under 3,200 games
15 of different risk conditions are calculated by RevSim. Power Risk and Market Price Study,
16 section 2.2.3; see also Documentation Table 2.3.8. Median prices and quantities of these
17 secondary sales, as well as mean market prices, are passed to RAM2014 for the purposes of the
18 secondary revenue credit and the computation of the load shaping rates.

19
20 The secondary revenues projected in RevSim are for market sales expected to be made by BPA
21 and do not include the portion of secondary energy that is expected to be sold to Slice customers.

22 The ratemaking process does not consider product choice by preference customers until the Rate
23 Design Step; therefore, the sales and revenue from RevSim are “grossed up” to reflect the market
24 value for all secondary energy expected to be produced by Federal generation. See

25 Documentation Table 2.3.8. Section 7(g) of the Northwest Power Act directs that all benefits
26 from the sale of excess electric power not otherwise allocated under section 7 be equitably
27 allocated to power rates in accordance with generally accepted ratemaking principles. Secondary

1 energy revenues are allocated to rate pools based on the FBS and new resources energy
2 allocation factors to credit the revenues against the costs of the resources producing the
3 secondary energy. See Documentation Table 2.3.8.

4 5 **2.1.5 Surplus Revenue Deficiency/Surplus Reallocation**

6 BPA sells surplus firm power under the FPS rate schedule. The COSA includes these sales in
7 the FPS rate pool and allocates costs to these sales. Sales of such firm power are not necessarily
8 made at rates that recover the exact costs allocated in the COSA to these sales. Therefore, either
9 a revenue surplus or a revenue deficiency will result when a comparison is made between the
10 costs allocated to the sales of this firm power and the revenues received from the sales of such
11 power. The expected revenue forecast from the sale of firm power, the allocated costs, and the
12 resulting revenue deficiency are shown in Documentation Table 2.3.9. This revenue deficiency
13 is allocated to all other firm power (PF, IP, and NR) rates. See Documentation Table 2.3.9.

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

19 20 **2.2 Rate Directives Step**

21 The Rate Directives Step reallocates costs among load pools to ensure that the relationships
22 between the rates for the different classes of customers comport with the rate directives in the
23 Northwest Power Act.

2.2.1 Rate Directives Step Modeling

The Rate Directives Step modeling takes as input the costs allocated to the four rate pools (PF, IP, NR, and FPS) from the COSA modeling. At this point in the modeling, the allocation of costs to the FPS rate pool is equal to the expected revenues from FPS sales and will not be altered throughout the remaining ratemaking steps. All costs and credits have been allocated to rate pools in the COSA. The Rate Directives Step will adjust the initial allocations among the PF, IP, and NR rate pools with reallocations of costs that conform with section 7 of the Northwest Power Act.

2.2.1.1 First IP-PF Rate Link

The IP rate for sales of power to BPA's DSI customers is a formula rate tied to the unbifurcated PF rate (*i.e.*, the PF rate at this point in the modeling includes costs that will be allocated between the PFp rate and the PFx rate later in the process). Also at this point in the modeling, the costs allocated to the IP and NR rate pools are equal on a per-megawatthour basis. Therefore, an adjustment is needed to set the IP rate to its proper relationship with the PF rate. That adjustment, the IP-PF Link 7(c)(2) rate adjustment, will reduce the allocated costs to the IP rate pool and increase the costs allocated to the PF and NR rate pools. The IP-PF Link adjustment sets the IP rate to be equal to the monthly/diurnal PFp energy rates applied to DSI billing determinants, plus the net industrial margin. The model first calculates the net industrial margin by subtracting the Value of Reserves provided by sales to the DSIs from the typical industrial margin calculated in the 7(c)(2) Margin Study, Appendix A of this Study. See Documentation Table 2.4.1. Monthly and diurnally differentiated PF melded rates are calculated as described in section 3.1.12. See Documentation Tables 2.4.2 and 2.4.3. Because the IP-PF Link calculation maintains a set relationship between the levels of the IP and PF rates for each year and simultaneously allocates costs between the two rates, and to avoid multiple iterations, RAM2014 has an algebraic formula to approximate a solution and then uses an intrinsic Excel

1 function, “Goal Seek,” to converge to a solution for each year of the rate test period. See
2 Documentation Table 2.4.4.

3
4 After the IP-PF Link reallocation, RAM2014 conducts an IP floor rate test to determine if the
5 currently calculated IP rate is below the IP rate that was in effect for the contract year ending on
6 June 30, 1985, as required by section 7(c)(2) of the Northwest Power Act. The currently
7 modeled (BP-14) IP rate at this point in the modeling is not below the IP floor rate, and no floor
8 rate adjustment is needed.

9 10 **2.2.1.2 Determine Active Exchanging Utilities**

11 With the proper relationship between the IP rate and the unbifurcated PF rate established, the
12 Base PF Exchange rates for the IOUs and the COUs can be calculated. The Base PF Exchange
13 rate for the IOUs is the average unbifurcated PF rate plus a transmission adder. The Base PF
14 Exchange rate for the COUs begins with the IOU rate and removes Tier 2 costs and loads. A test
15 is conducted to determine if the ASCs of the potential IOU and COU exchanging utilities are
16 greater than the IOU and COU Base PF Exchange rates. If a utility’s ASC is greater than its
17 Base PF Exchange rate, the utility becomes an active exchanging utility.

18 19 **2.2.1.3 Calculate 7(b)(2) Rate Protection and 7(b)(3) Reallocations**

20 The next step is to calculate the level of rate protection due to preference customers pursuant to
21 section 7(b)(2) of the Northwest Power Act. The BP-14 rates are calculated pursuant to a
22 settlement of the outstanding litigation associated with the REP and the section 7(b)(2) rate test.
23 2012 Residential Exchange Program Settlement Agreement, contract no. 11PB-12322 (2012
24 REP Settlement). The 2012 REP Settlement was previously evaluated for compliance with,
25 among other statutory provisions, sections 7(b)(2) and 7(b)(3).

1 Rate modeling for the REP under the 2012 REP Settlement begins with total IOU REP benefits,
2 as specified in the 2012 REP Settlement and known as Scheduled Amounts. Added to this total
3 IOU REP benefit amount are the Refund Amounts, also specified in the 2012 REP Settlement.
4 The Refund Amounts are credited back to preference customers in the form of a credit on their
5 power bills. Together these amounts are referred to as REP Recovery Amounts. See
6 Documentation Table 2.4.9.

7
8 The REP Settlement rates modeling first calculates the Unconstrained Benefits, which are the
9 REP benefits that would be in place if there was no PFp rate protection. In such circumstance,
10 the REP benefits for each exchanging utility would be its ASC minus its appropriate Base PFx
11 rate multiplied by its qualified exchange load. The Unconstrained Benefits are shown in
12 Documentation Table 2.4.10. These Unconstrained Benefits are then used to calculate COU
13 REP benefits, as specified in individual settlements with each eligible COU. COU REP benefits
14 are calculated using a ratio of (i) the IOU Scheduled Amounts plus COU Refund Amount to
15 (ii) the 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 the
19 Unconstrained Benefits and the total IOU and COU REP benefits determined, the first part of
20 rate protection due to preference customers is calculated as the Unconstrained Benefits minus the
21 sum of REP benefits. The REP Settlement modeling then allocates this amount to individual
22 REP participants. Next, the cost of providing Refund Amounts is allocated to the IOU REP
23 participants. The sum of these two specific allocations to each REP participant is divided by the
24 exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge that is added
25 to the appropriate Base PFx rates to produce a utility-specific PFx rate. See Documentation

1 Table 2.4.11. After the utility-specific PFX rates are calculated, the utility-specific REP benefits
2 are calculated and summed. See Documentation Table 2.4.11.

3
4 A second part of rate protection, the REP Surcharge, is calculated and allocated to the IP and NR
5 rate pools. The REP Surcharge is determined by multiplying the REP benefit costs determined
6 above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in the 2012 REP
7 Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the IP and NR rates and
8 changes this historical 7(b)(3) rate surcharge as REP Recovery Amounts change. The REP
9 Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules, produces
10 an amount of rate protection dollars. See Documentation Table 2.4.13. This amount is allocated
11 to the IP and NR rate pools.

12
13 The RAM2014 REP Settlement modeling explicitly adjusts dollars among the PFp, PFX, IP, and
14 NR rate pools. The REP Settlement rate protection allocations increase the IP, NR, and PFX
15 rates while decreasing the PFp rate. See Documentation Table 2.4.14.

16 17 **2.2.1.4 Second IP-PF Rate Link**

18 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must be
19 adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second IP-PF
20 Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set equal to
21 the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. See Documentation
22 Tables 2.4.16, 2.4.17, and 2.4.18.

23 24 **2.2.2 IP Rate**

25 The IP rate is calculated using directives in sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest
26 Power Act. Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will

1 be set “at a level which the Administrator determines to be equitable in relation to the retail rates
2 charged by the public body and cooperative customers to their industrial consumers in the
3 region.” “Equitable in relation” pursuant to section 7(c)(2) is defined as basing the DSI rate on
4 BPA’s “applicable wholesale rates” to its COU customers plus the “typical margins” included by
5 those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rate is to be
6 adjusted to account for the value of power system reserves provided through contractual rights
7 that allow BPA to restrict portions of the DSI load. This adjustment is made through a Value of
8 Reserves credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale
9 rate, plus the typical margin, plus the VOR credit, subject to the DSI floor rate test and the
10 outcome of the determination of PFp rate protection.

11 12 **2.2.2.1 Applicable Wholesale Rate**

13 The applicable wholesale rate is calculated as the rate(s) at which BPA is selling power to COUs,
14 that is, the PFp rate (for general requirements, as defined in section 7(b)(4) of the Northwest
15 Power Act) and the NR rate (for New Large Single Loads). The IP rate begins by being set to
16 the average of the PF and NR rates, weighted by sales to COUs at each rate and reflecting the
17 DSI class load factor. No sales to COUs at the NR rate are projected for this rate period.

18 19 **2.2.2.2 Typical Margin, Value of Reserves, and Net Industrial Margin**

20 As noted above, the DSI rate is set by adding the typical margin and VOR credit to the
21 applicable wholesale rate. The typical margin is calculated as described in section 3.3.1.2 and
22 Appendix A. The VOR credit is calculated as described in section 3.3.1.1. The typical margin
23 plus the VOR credit yields the net industrial margin. The net industrial margin is added to the
24 applicable wholesale rate, and the result is multiplied by the forecast DSI load to determine the
25 allocated costs for the IP rate pool. See Documentation Table 2.4.1.

1 **2.2.2.3 IP-PF Link 7(c)(2) Adjustment**

2 The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the
3 revenues expected to be recovered from the DSIs at the final IP rate and the costs allocated to the
4 rate. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the
5 PF rate. Because the allocation of the 7(c)(2) Delta changes the PF and the NR rates, together
6 forming the applicable wholesale rate upon which the IP rate is based, the 7(c)(2) Delta must be
7 recalculated. The interaction between the applicable wholesale rate and the IP rate has been
8 reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic
9 Excel function, "Goal Seek," to converge to a solution for each year of the rate test period. See
10 Documentation Table 2.4.4.

11
12 **2.2.2.4 IP Floor Rate Verification**

13 Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers shall not be
14 less than the rates in effect for the contract year ending June 30, 1985 (the floor rate).
15 Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate.
16 If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers
17 with the increased revenue from the DSIs. If the IP rate is set at a level above the floor rate, no
18 floor rate adjustment is necessary.

19
20 The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate
21 period (FY 2014-2015) DSI billing determinants. The resulting revenue figure is divided by
22 total IP rate period energy loads to arrive at an average rate in mills per kilowatthour. This rate
23 is reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the
24 IP-83 rate but are no longer applicable. Both adjustments are made on a mills per kilowatthour
25 basis.

1 In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor
2 rate comparison. The floor rate is adjusted for transmission costs by subtracting total
3 transmission costs in mills per kilowatthour from the IP-83 rate in the same manner that the
4 Exchange Cost Adjustment and Deferral Adjustment are removed. The mills per kilowatthour
5 component is determined by dividing total transmission costs in the IP-83 rate by the total energy
6 billing determinants for that rate period. See Documentation Table 2.4.6.

7
8 These calculations result in an undelivered IP floor rate. The floor rate is applied to the current
9 rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed
10 IP rates is compared to the revenue at the floor rate. Because revenue from the proposed IP rate
11 is greater than the floor rate revenue, no floor rate adjustment is necessary. See Documentation
12 Tables 2.4.6 and 2.4.7.

14 **2.2.3 Section 7(b)(2) Rate Protection**

15 The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's rates for
16 public body, cooperative, and Federal agency customers (collectively referred to as preference
17 customers or 7(b)(2) customers) are no higher than rates calculated using specific assumptions
18 that remove certain effects of the Northwest Power Act. For BP-14 rates, the rate test was
19 performed in the assessment of the 2012 REP Settlement. The 2012 REP Settlement was found
20 to be in compliance with the rate test, and rates are established pursuant to the 2012 REP
21 Settlement.

23 **2.3 Rate Design Step**

24 The Rate Design Step uses the results of the cost and credit allocations of the COSA Step, as
25 modified by the Rate Directives Step, to develop the rate components that would recover the
26 costs allocated to each rate pool. Three distinct rate designs are developed: (1) a tiered rate

1 design for the PFp rate, in which the Tier 1 rates are designed using customer charges and
2 demand and energy rates; (2) a traditional demand and energy design for the PFp Melded rate,
3 the IP rate, and the NR rate; and (3) a constant annual energy rate for each PFp Tier 2 rate and
4 the PFx rates.

6 **2.3.1 Rate Design Step Modeling**

7 Based on the results of the Rate Directives Step, RAM2014 designs rates for each rate pool. For
8 the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied
9 without further processing. The design of the PFp Melded rate is described in section 3.1.12.
10 The design of the PFx rate is described in section 3.2. The design of the IP rate is described in
11 section 3.3. The design of the NR rate is described in section 3.4.

13 **2.3.1.1 TRM Rate Modeling**

14 Additional processing is required before the PFp rate design can be calculated. The allocations
15 of costs and credits performed in the COSA Step and Rate Directives Step are insufficient to
16 inform the rate design of the PFp rate. The TRM specifies a cost allocation methodology to
17 separate costs into the various TRM cost pools in a manner different from the COSA. RAM2014
18 accomplishes this different cost allocation through a process of mapping disaggregated costs and
19 credits to the TRM cost pools. To provide a crosswalk between the differences between COSA
20 allocations and TRM allocations, the mapping for each is shown within RAM2014, as described
21 below.

22
23 The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue
24 Requirement Study, credits passed from the revenue forecast, and cost and credit line items
25 internally computed in RAM2014. Internally computed line items include:

- 26 • Costs of IRD and LDD programs.

- 1 • Revenues associated with power sales to DSI customers at the IP rate.
- 2 • Revenues and costs associated with the Residential Exchange Program:
 - 3 ○ Revenues are calculated at the PFX Rates, incorporating REP surcharges. Loads are
 - 4 included only for customers qualifying for exchange benefits.
 - 5 ○ Costs are calculated using the ASC and exchange load for each qualifying REP
 - 6 participant.
- 7 • Revenues associated with power sales at the NR rate.
- 8 • System augmentation costs required to achieve annual load-resource balance.
- 9 • Balancing power purchase costs required to serve the monthly/diurnal loads of Load
- 10 Following customers.
- 11 • “Balancing” augmentation power purchases associated solely with provision of power at
- 12 the Load Shaping rate on a net annual basis. (Load Shaping rate loads would equal zero
- 13 on a net annual basis except that Above-RHWM loads less than one average megawatt
- 14 are allowed to forgo purchasing at Tier 2 rates and be served at the Load Shaping rate.)
- 15 • Secondary energy revenues credit.
- 16 • Revenues allocated for Unused RHWMs. See section 3.1.3.2.
- 17 • Demand and Load Shaping revenues. See sections 3.1.2.4 and 3.1.2.3.
- 18 • Cost of Network real power losses on sales to non-Slice preference customers. See
- 19 section 3.1.3.1.
- 20 • Tier 2 overhead costs and other cost assignments. See section 3.1.4.1.

21

22 Once all costs have been mapped into TRM cost pools, the rate design for the PF Public rate can

23 be applied.

24

25

26

2.3.2 PF Public Rate Design Step for Tiered Rates

The rate design for the PFp rate is established in the TRM. The TRM specifies that all costs and credits comprising BPA's total power revenue requirement be allocated to one of four Customer Charge cost pools: Composite, Non-Slice, Slice, or Tier 2. The Tier 2 cost pool is further divided into VR1-2014, Short-Term, and Load Growth cost pools. After reflecting the cost allocations to other rate pools, the end result of the TRM cost allocations is that the total costs allocated to the four Customer Charge cost pools will equal the total costs allocated to the PFp rate pool in the COSA Step and the Rate Directives Step. Thus, the TRM cost allocations neither increase nor decrease the cost allocations to the PFp rate pool after the Rate Directives Step. A demonstration of this equivalence is shown in Documentation Table 2.5.8.2.

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

2.3.2.1 Composite Cost Pool

Except for costs and credits distinctly associated with a particular primary product, all Tier 1 costs and credits are allocated to the Composite cost pool. The Composite cost pool forms the cost basis for the Composite Customer rate, which is paid by all preference customers with a CHWM contract.

1 **2.3.2.2 Non-Slice Cost Pool**

2 Tier 1 costs and credits, primarily secondary revenues, that are not associated with the Slice
3 product are allocated to the Non-Slice cost pool. The Non-Slice cost pool forms the cost basis
4 for the Non-Slice Customer rate, which is paid by preference customers that have selected the
5 Load Following product or the Block product; it is also paid by customers selecting the
6 Slice/Block product for their Block purchases.

7
8 **2.3.2.3 Slice Cost Pool**

9 Tier 1 costs and credits that are associated with the Slice product are allocated to the Slice cost
10 pool. The Slice cost pool forms the cost basis for the Slice Customer rate, which is paid by
11 preference customers that have selected the Slice/Block product for their Slice purchases. In the
12 BP-14 rates there are no costs allocated to this cost pool.

13
14 **2.3.2.4 Tier 2 Cost Pools**

15 Costs and credits that are associated with the sale of power to serve a customer's Above-RHWM
16 load are allocated to Tier 2 cost pools. Generally, the costs allocated to a Tier 2 cost pool are
17 purchase power costs designated by BPA as being for this purpose. In addition to purchase
18 power costs, Tier 2 rates are established to recover Resource Support Services, overhead, and
19 other BPA costs that are not necessarily incurred solely for the purpose of serving Above-
20 RHWM load, but are supportive in part of making such sales. The initial allocation of these
21 other costs is to either the Composite cost pool or the Non-Slice cost pool. Therefore, the
22 portion of the revenues expected to be received from sales at a Tier 2 rate is reassigned to the
23 cost pool where the initial allocation is made. See Documentation Table 2.5.7.2.

1 **2.4 Rate Modeling Iterations**

2 Several iterations—both internally within RAM2014 and externally between other models and
3 RAM2014—are required before the ratesetting process is complete. These iterations ensure that
4 the appropriate costs are computed and allocated consistent with the principles of the Northwest
5 Power Act and TRM rate design.

6 7 **2.4.1 Iterations Internal to the Model**

8 **2.4.1.1 Participation in the Residential Exchange Program**

9 Participation in the REP requires that the applicable Base PFX rate is less than a participant's
10 Average System Cost. The applicable Base PFX rate is either the Base Tier 1 PFX rate for COUs
11 or the untiered Base PFX rate for IOUs. If a utility has an ASC less than its applicable Base PFX
12 rate, that utility is ineligible to participate in the REP. RAM2014 uses a macro loop feature to
13 test whether, for each year of the exchange period, each utility with an ASC qualifies for the
14 REP. If a utility does not qualify, a binary index is used to exclude it, and if it does qualify, the
15 index is set to include it. This test is done such that the exchange resource costs are calculated
16 including the resources purchased from only REP participants, and before the Rate Directives
17 Step of the 7(c)(2) linking of the IP and PF rates, the determination of rate protection, and
18 subsequent reallocation of rate protection.

19 20 **2.4.1.2 Costs of Rate Discounts**

21 The costs of the LDD and IRD (see sections 2.1.3.3 and 2.1.3.4) are mathematically related to
22 Composite, Non-Slice, and Slice customer charges, and these charges are dependent on REP
23 benefits and IP and NR revenues. LDD and IRD costs are indeterminate until final charges are
24 set; however, since final charges are in part dependent upon the costs associated with these other
25 factors, iteration in the model is necessary. As explained in sections 2.1.3.3 and 2.1.3.4,
26 RAM2014 computes the cost of the LDD based on offset quantities and the IRD rate based on a

1 historical percentage, which are applied to internally computed customer charges. For each
2 iteration of the model, the appropriate charges are applied, and new discount costs are computed.
3 These new discount costs are allocated in the COSA Step, and the Rate Directives Step and TRM
4 Step are performed again. New charges and rates are computed, which are again applied to the
5 discount calculations. The iterative process continues until convergence.

6 7 **2.4.1.3 Contract Formula Rates**

8 If a power sales contract rate was computed based on the results of rate modeling, an iterative
9 approach might be required to solve for the amount of revenue to be credited in the COSA Step.
10 No internal iterations are currently required to model contracts at formula rates.

11 12 **2.4.2 Iterations External to the Model**

13 Some aspects of the ratesetting process are dependent upon the rates computed in RAM2014.
14 Many of these dependencies have been integrated within RAM2014, as described above. Other
15 dependencies are simply too large to incorporate into one model. Thus, external iterations must
16 be performed before rates can be finalized.

17 18 **2.4.2.1 Consumer-Owned Utility Average System Costs**

19 The ASCs of COUs participating in the REP are based in part on the cost of power purchased
20 from BPA at rates determined in RAM2014. The amount of Refund Amount that the COU will
21 receive is also dependent upon the COU's TOCA. These two factors require a recomputation of
22 ASCs for COUs based on the PFp rate level and the Refund Amount. This iteration is manually
23 performed between RAM2014 and the ASC forecast model. Revised ASCs are included in
24 RAM2014, and rate levels are recomputed until the results converge.

1 **2.4.2.2 Risk Analysis and Mitigation: PNRR**

2 PNRR is an amount of net revenues required from power rates to ensure that cash flows from
3 proposed rates meet BPA’s Treasury Payment Probability (TPP) standard. The amount of PNRR
4 is the result of an iterative process among four models: RAM2014, RevSim, NORM, and
5 ToolKit. See Power Risk and Market Price Study section 3.3. The iterative process is initiated
6 with a seed value for PNRR in the revenue requirement used in RAM2014. The resultant rates
7 are used in RevSim and NORM to produce distributions of net revenues. These distributions are
8 then used in the ToolKit to produce a new PNRR value for the RAM2014 revenue requirement.
9 See Documentation section 2. Because PNRR for the BP-14 rates is determined to be zero, no
10 iterative process is required to determine rate levels for the BP-14 rates.

11
12 **2.4.2.3 Revised Revenue Test**

13 The revenue forecast quantifies the expected level of sales and revenue from power rates and
14 other sources for the rate period, FY 2014-2015. Two revenue forecasts are prepared, one with
15 current rates and the other with proposed rates. These forecasts are used to test whether current
16 rates will recover the generation revenue requirement and, if not, whether proposed rates are
17 sufficient to recover the generation revenue requirement. The revenue test is described in
18 section 4 of this Study and in Power Revenue Requirement Study section 3.3. The power rates
19 placed in effect October 1, 2011, are used in the calculation of revenue at current rates for
20 FY 2014-2015, using the load forecast from the Power Loads and Resources Study.

21
22 The rates as computed in RAM2014 are applied to the same loads to create a revenue forecast at
23 proposed rates for FY 2014-2015. The revenue from this forecast is shown in Documentation
24 Table 4.2. These revenues are incorporated into the revenue test in Power Revenue Requirement
25 Study section 4 to determine if the proposed rates are sufficient to recover the revenue
26 requirement. If the rates are not sufficient, an adjustment to the rates is required to increase the
27 rates to a level sufficient to recover the revenue requirement.

1 The revised revenue test demonstrates that the BP-14 rates are sufficient to recover the revenue
2 requirement, and no further rate adjustment is needed. See Power Revenue Requirement Study
3 section 4.
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1 **3. RATE DESIGN**

2 As described in section 1.2.3, the Administrator retains a considerable amount of discretion in
3 designing rates, as long as the rates meet the requirements of section 7 of the Northwest Power
4 Act.

5
6 Rate design is applied after BPA has allocated its total power revenue requirement to five rate
7 pools: Priority Firm Public Power, Priority Firm Exchange Power, Industrial Firm Power, New
8 Resources Firm Power, and Firm Power Products and Services. Rate design does not change the
9 amount of the revenue requirement that is allocated to each of the five rate pools. Rather, rate
10 design determines how the revenue requirement is to be collected through rates for each of the
11 five rate pools. One purpose of rate design is to target the revenue collection within a particular
12 rate pool and to distinguish between different types of service and power consumption of
13 individual wholesale power customers. Another purpose is to provide price signals to customers
14 to encourage more efficient power usage and differentiate between the relative market values of
15 the products and services BPA offers to its customers.

16
17 This section of the Power Rates Study describes the rate design for peaking capacity use, time-
18 of-day use, and seasonal use of power purchased from BPA under its Priority Firm Power
19 (PF-14), Industrial Firm Power (IP-14), and New Resources Firm Power (NR-14) rate schedules.

20
21 There are three Priority Firm Power rates: the PFp rate, the PFx rate, and the Priority Firm
22 Melded rate. PFp rate design is applicable to purchases by public bodies, cooperatives, and
23 Federal agencies pursuant to CHWM contracts. The PFx rate design is applicable to purchases
24 by utilities pursuant to a Residential Purchase and Sale Agreement (eligible consumer-owned
25 utilities) or Residential Exchange Program Settlement Implementation Agreement (eligible
26 investor-owned utilities). The PF Melded rate design is applicable to purchases by public bodies,

1 cooperatives, and Federal agencies pursuant to power sales contracts other than CHWM
2 contracts. No sales under the PF Melded rate are forecast during the rate period, FY 2014–2015.

3
4 The PFp rate design is based on the design set forth in the Tiered Rate Methodology, BP-12-
5 A-03. The TRM established a rate design for the PFp rate schedule to be used for power sales
6 under BPA’s CHWM contracts.

7
8 The PFX rate schedule is also described in this section. Due to the annual design of the
9 Residential Exchange Program, application of a PFX rate schedule rate design that includes rate
10 differentiation for peaking capacity use, time-of-day use, and seasonal use of power purchased
11 from BPA was deemed unnecessary.

12
13 The TRM did not establish a rate design for the PFX, IP, and NR rate schedules. The rate design
14 for IP and NR service is described in this Study, and the specific rates are set forth in the Power
15 Rate Schedules, BP-14-A-03-AP01. Certain PFp design elements adopted in the TRM are used
16 in the IP-14 and NR-14 rate design, in particular the method for scaling energy rates from the
17 market forecast and the general method for calculating the demand billing determinant.

18 19 **3.1 Priority Firm Public Rate Design**

20 As described in the TRM, the PFp rate design includes two tiers. The tiering of the rates is a
21 ratemaking construct that allocates the costs and credits functionalized to power; it is not an
22 allocation of power to customers. The costs and credits functionalized to power are allocated to
23 the Tier 1 and Tier 2 cost pools based upon the principle of cost causation. The forecast costs
24 and credits allocated to Tier 1 cost pools are kept separate and distinct from those allocated to the
25 Tier 2 cost pools.

1 In addition to creating the Tier 1 and Tier 2 cost pools, the TRM specifies a rate design for the
2 Tier 1 rates. Tier 1 rates include three customer charges: the Composite Customer Charge, the
3 Non-Slice Customer Charge, and the Slice Customer Charge. These charges recover the costs
4 allocated to their respective cost pools. The rate for each of the customer charges is a dollar
5 amount per each one percentage point of the billing determinant. For each customer charge,
6 each customer's billing determinant will be, respectively, its Tier 1 Cost Allocator (TOCA), its
7 Non-Slice TOCA, or its Slice Percentage. In addition to the customer charges, the Tier 1 rates
8 include 24 monthly/diurnal Load Shaping rates and a Demand Charge with 12 monthly Demand
9 rates.

10
11 Tier 2 rates coincide with the three Tier 2 rate options elected by customers to meet their Above-
12 RHWM load obligation. In PF-14 these are the Tier 2 Short-Term, Load Growth, and VR1-2014
13 rates. The VR1-2014 rate is the first Tier 2 Vintage rate offered under the CHWM contracts.

14
15 Two other rates are calculated based on the TRM "component" rates. First is the PFp Tier 1
16 Equivalent Rate for use in contracts that have rates that are tied to a traditional PF HLH/LLH
17 rate design. Second, a PFp Melded rate schedule is included should BPA need to serve load of a
18 preference customer that does not have a CHWM contract.

19 20 **3.1.1 PFp Customer Cost Pools**

21 Under the TRM, there are three Tier 1 cost pools (Composite, Non-Slice, and Slice) and the
22 possibility of multiple Tier 2 cost pools. For the FY 2014–2015 rate period there are three Tier 2
23 cost pools: Short-Term, Load Growth, and VR1-2014. The method by which costs and credits
24 are allocated among the six PFp cost pools is directed by the TRM. Costs and credits are
25 allocated among the cost pools based on the association of the cost or credit with a product (Load
26 Following, Block, or Slice/Block) and a tier (Tier 1 or Tier 2). The Composite cost pool includes

1 all Tier 1 costs and credits that are not otherwise allocated to the Slice and Non-Slice cost pools.
2 The Slice cost pool includes only those costs and credits that are specifically and uniquely
3 attributed to the Slice product. Likewise, the Non-Slice cost pool includes only those costs and
4 credits that are specifically and uniquely attributed to the Load Following and Block products
5 (including the Block portion of the Slice/Block product). The Tier 2 Short-Term, Load Growth,
6 and VR1-2014 cost pools include all costs and credits that are attributable to the resources and
7 services necessary for load served at a Tier 2 rate. Additional detail on the cost pools is found in
8 section 3.1.7 below.

9
10 To calculate the Tier 1 and Tier 2 rates, all costs and credits are allocated to the appropriate cost
11 pools; all costs functionalized to generation are allocated to one of the six PFp cost pools
12 (Composite, Non-Slice, Slice, Short-Term, Load Growth, and VR1-2014). As described in
13 section 2.1, the same costs and credits have also been allocated to the PF rate pool and the IP,
14 NR, and FPS rate pools. To account for the costs and credits allocated to the rate pools other
15 than PF, the revenues recoverable from those rate pools have reduced the costs allocated to the
16 Composite cost pool. A demonstration is included in RAM2014 that shows that the revenue
17 requirement allocated to the PFp rate pools in the COSA equals the costs and credits allocated to
18 the PFp cost pools after the reductions from the other rate pools. See Documentation
19 Tables 2.5.7.1 and 2.5.7.2.

20
21 Once costs and rate design revenue credits have been balanced with the revenue requirement, to
22 the extent necessary additional adjustments to the PFp cost pools are made to avoid cost shifts
23 among products (Load Following, Block, and Slice/Block), and tiers (Tier 1 and Tier 2). These
24 rate design adjustments move dollars from one cost pool to another through equal credits and
25 debits and do not change the overall revenue requirement or the cost allocations among PF, IP,
26 NR, and FPS. These rate design adjustments include three adjustments made within Tier 1

1 (section 3.1.3) and one adjustment made between Tier 1 and Tier 2 (section 3.1.4). The three
2 adjustments made within Tier 1 are the Transmission Loss Adjustment, the Firm Surplus and
3 Secondary Adjustment from Unused RHW, and the Balancing Augmentation Adjustment.
4 The one adjustment made between Tier 1 and Tier 2 is the Tier 2 Overhead Adjustment. The
5 complete allocation of costs with all revenue credits and adjustments for the six cost pools can be
6 found in Documentation Table 2.3.5, and TRM allocation of cost pool adjustments can be found
7 in Documentation Table 2.5.6.

8 9 **3.1.2 Rate Design Revenue Credits**

10 The Composite and Non-Slice cost pools contain credits for revenues collected from other
11 components of the PFp rates. The Composite cost pool includes a credit for forecast revenue
12 collectable from the sale of Resource Support Services. The Non-Slice cost pool includes a
13 credit for forecast revenue collectable through the Load Shaping, Demand, and Resource
14 Shaping charges. All of these rate design credits are necessary to ensure that the PFp rates do
15 not over-collect the allocated revenue requirement and that the costs and credits have been
16 allocated as specified in the TRM.

17 18 **3.1.2.1 Resource Support Services (RSS) Revenue Credit**

19 BPA provides RSS and RSS-related service options that generate revenue from preference
20 customers. Revenue received from RSS is credited to the Composite cost pool. For
21 transparency purposes, BPA committed in the TRM to apply applicable RSS to resources serving
22 system augmentation needs (currently Klondike III) and to resources supporting the Tier 2 rates,
23 if appropriate. In these situations, the source of the RSS revenue credit to the Composite cost
24 pool is provided through either an RSS adder to the system augmentation cost or an RSS cost
25 within a Tier 2 cost pool.

1 The total annual RSS revenue credit for FY 2014–2015 can be found in Documentation
2 Table 3.1.

3.1.2.2 Resource Shaping Charge (RSC) Revenue Credit

5 All balancing purchase costs, either resource or load, are allocated to the Non-Slice cost pool.
6 The RSC collects additional revenue for balancing purchase costs associated with balancing
7 resources against a flat annual block. To pair cost allocation with revenue collection of
8 balancing purchase costs, the forecast RSC revenue credit is applied to the Non-Slice cost pool.

10 BPA committed in the TRM to apply RSS and the RSC to resources serving system
11 augmentation needs (Klondike III) and to resources supporting the Tier 2 rates in order to make
12 these acquisitions financially equivalent to a flat block. See TRM section 8. In these situations,
13 the source of the RSC revenue credit is provided through either an RSC adder to the system
14 augmentation cost or an RSC adder within a Tier 2 cost pool. The forecast annual RSC revenue
15 credit for FY 2014–2015 can be found in Documentation Table 3.1.

3.1.2.3 Load Shaping Revenue Credit

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

1 **3.1.2.4 Demand Revenue Credit**

2 The Demand charge is designed to send a price signal to a limited portion of a customer’s overall
3 demand on BPA and is applicable to customers purchasing Load Following and Block with
4 Shaping Capacity products. Forecast revenue from the Demand charge is credited to the Non-
5 Slice cost pool by means of the Demand Revenue Credit.

6
7 **3.1.3 Rate Design Adjustments Made Between Tier 1 Cost Pools**

8 **3.1.3.1 Transmission Loss Adjustments**

9 The Transmission Loss Adjustments provide a credit to the Composite cost pool and an equal
10 debit to the Non-Slice cost pool based on Non-Slice transmission losses. The Transmission Loss
11 Adjustments account for different accounting of transmission losses for the Slice/Block and Non-
12 Slice products. The Non-Slice products and the Block portion of the Slice/Block products are
13 delivered to the purchaser’s load service area, while the Slice product is delivered to the
14 purchaser at BPA’s generation bus bar. The cost of generating the real power losses for the
15 transmission of Non-Slice sales is included in BPA’s revenue requirement. Conversely, the cost
16 of generating the real power losses for the transmission of Slice sales is borne by the purchaser.
17 The Transmission Loss Adjustments transfer the cost of generating the real power losses for the
18 transmission of Non-Slice PF sales from the Composite cost pool to the Non-Slice cost pool.
19 The Transmission Loss Adjustments are calculated by multiplying the network losses associated
20 with the Non-Slice PF products, including the Block portion of the Slice/Block product, by the
21 Average Slice and Non-Slice Tier 1 rate (see Documentation Table 2.5.6). The calculation and
22 result of the Transmission Loss Adjustments can be found in Documentation Table 2.5.3.

1 **3.1.3.2 Firm Surplus and Secondary Adjustments from Unused RHW**

2 Unused RHW occurs when a customer's Forecast Net Requirement is less than its RHW.

3 The Firm Surplus and Secondary Adjustments from Unused RHW reallocate costs between the
4 Composite cost pool and the Non-Slice cost pool.

5
6 Unused RHW reduces the need for system augmentation and/or increases firm power available
7 for sale in the market. The reduced augmentation expenses and/or increased firm power market
8 revenues are reflected in three lines on the TRM cost table: (1) Augmentation Power Purchases;
9 (2) Secondary Revenue; and (3) Balancing Purchases. See Documentation Table 2.5.1. The
10 Augmentation Power Purchases line is part of the Composite cost pool, and the Secondary
11 Revenue and Balancing Purchases are part of the Non-Slice cost pool. To share the entire
12 benefit of Unused RHW with all customers, the Composite and Non-Slice cost pools contain a
13 Firm Surplus and Secondary Adjustment (from Unused RHW), with one reflecting a credit and
14 the other an equal debit.

15
16 The Firm Surplus and Secondary Adjustments have two purposes. The first is to reflect the
17 difference between the value of a flat annual block of system augmentation and the value of the
18 Unused RHW when the Unused RHW displaces augmentation. The difference between a
19 flat annual block of system augmentation and the shape of the Unused RHW is reflected in
20 changes in the assumed balancing purchases and associated costs. These changes in balancing
21 purchase costs are captured in the Non-Slice cost pool. A Firm Surplus and Secondary
22 Adjustment reallocates the change in balancing purchase costs associated with the difference in
23 value from the Non-Slice cost pool to the Composite cost pool.

24
25 The second purpose of the Firm Surplus and Secondary Adjustments is to reflect the full value of
26 the Unused RHW when the Unused RHW creates firm surplus power. The revenue
27 associated with this change in firm surplus power related to the Unused RHW is reflected in

1 the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary
2 Adjustment reallocates this change in secondary revenues associated with the Unused RHW
3 from the Non-Slice cost pool to the Composite cost pool.
4

5 The value of Unused RHW consists of portions of RHW Augmentation, Tier 1 System Firm
6 Critical Output, and an associated portion of secondary energy. Each of these three components
7 is valued at its respective price: the Augmentation price for the RHW Augmentation
8 component, the market price (as expressed by the Load Shaping rates) for the Tier 1 System
9 Firm Critical Output component, and the market price (as expressed by the average price
10 received for secondary sales) for the secondary component. The value of Unused RHW
11 (expressed in dollars per megawatthour) also will be calculated for use in the Slice True-Up of
12 the Firm Surplus and Secondary Adjustment line item in the Composite cost pool.
13

14 See Documentation Table 2.5.2 for results and calculation of the Firm Surplus and Secondary
15 Adjustments from Unused RHW and the dollar per megawatthour Slice True-Up value of
16 Unused RHW.
17

18 **3.1.3.3 Balancing Augmentation Load Adjustments**

19 Balancing augmentation load is (1) Above-RHW load that is forecast to be served at Load
20 Shaping rates, rather than at Tier 2 rates or with a non-Federal resource (net positive Load
21 Shaping billing determinants); (2) load that is forecast to be served at Tier 2 rates or with a non-
22 Federal resource, rather than at the appropriate Tier 1 rates (net negative Load Shaping billing
23 determinants); or (3) changes to the Tier 1 System during the applicable 7(i) ratesetting process
24 from that used to establish each customer's allocation of the Tier 1 System during the applicable
25 RHW Process.
26

1 The sum total of these conditions for FY 2014 is a charge to the Composite cost pool and an
2 offsetting credit to the Non-Slice cost pool. The sum total of these conditions for FY 2015 is a
3 credit to the Composite cost pool and an offsetting charge to the Non-Slice cost pool. See
4 Documentation Tables 2.5.6.1 and 2.5.6.2.

6 **3.1.3.3.1 Above-RHWM Load that is Forecast to be Served at Load Shaping Rates**

7 This first condition occurs when Above-RHWM load is forecast to be served at Load Shaping
8 rates either when a Load Following customer's annual Above-RHWM load is less than
9 8,760 MWh and the Load Following customer made no alternative election to serve its Above-
10 RHWM load, or when Above-RHWM load is determined in the RHWM Process and the load
11 forecast is updated during the rate proceeding to reflect the forecast of a larger load. When this
12 is the case and the amount of system augmentation purchases is equal to or greater than the
13 amount of balancing augmentation load, the acquisition costs attributable to supplying balancing
14 augmentation load are included as a system augmentation expense in the Composite cost pool.
15 The revenue from supplying balancing augmentation load is credited to the Non-Slice cost pool
16 through the Load Shaping charge revenue credit. Without a Balancing Augmentation Load
17 Adjustment, only Non-Slice customers would receive a credit through an increased Load
18 Shaping Charge revenue credit, but both Slice and Non-Slice customers would bear the cost of
19 an increased system augmentation expense. The Balancing Augmentation Load Adjustment
20 corrects this inequity with a credit to the Composite cost pool and an equal debit to the Non-Slice
21 cost pool.

22
23 This case causes the sum of Load Shaping billing determinants to be positive. The Balancing
24 Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as
25 the lesser of the sum of the Load Shaping billing determinants for each fiscal year or the

1 augmentation amount for each fiscal year. The result is multiplied by the augmentation price for
2 the respective fiscal year.

3
4 **3.1.3.3.2 Load that is Forecast to be Served at Tier 2 Rates or with a Non-Federal**
5 **Resource**

6 This second condition occurs when load that would otherwise be served at Tier 1 rates is served
7 at Tier 2 rates or with a non-Federal resource when Above-RHWM load is determined and the
8 load forecast is updated during the rate proceeding to reflect the forecast of a smaller load.

9 When this is the case, there is a reduction in system augmentation expenses from what would
10 have otherwise occurred. The Composite cost pool would have received an implicit reduction in
11 costs due solely to load variation attributable to Non-Slice customer loads. In this case, the
12 Balancing Augmentation Adjustment is a debit to the Composite cost pool and an equal credit to
13 the Non-Slice cost pool.

14
15 This case causes the sum of the Load Shaping billing determinants to be negative. The
16 Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are
17 calculated as the greater of (1) the sum of the Load Shaping billing determinants for each fiscal
18 year and (2) the avoided augmentation amount for each fiscal year. The result is multiplied by
19 the augmentation price for the respective fiscal year.

20
21 **3.1.3.3.3 Changes to the Tier 1 System During the Applicable 7(i) Ratesetting Process**

22 This third condition occurs when the T1SFCO used for the calculations of the RHWMs is
23 updated in the 7(i) proceeding, which results in an updated Tier 1 System output. Any difference
24 resulting from the updated calculation of the Tier 1 System output in the rate proceeding will
25 cause either a cost or a credit to be included in the Balancing Augmentation Load Adjustment.
26 The cost or credit is included as an addition to the Balancing Augmentation Adjustment rather
27 than in the Balancing Power Purchase costs computed in RevSim. Movements in the updated

1 Tier 1 System output will increase or decrease on an annual-average basis the amount of
2 Augmentation required, which is considered Balancing Power Purchases under the TRM.
3 RevSim computes Balancing Power Purchase costs after load-resource balance has been
4 achieved under critical water. See section 3.3 of the TRM. If the size of the Tier 1 System
5 output increases relative to the RHWMTier 1 System output, the Non-Slice cost pool will
6 receive a credit for this additional anticipated energy. Alternatively, if the size of the Tier 1
7 System output decreases, the Non-Slice cost pool will be charged for the reduction in anticipated
8 energy. Customers purchasing the Slice/Block product receive either more or less energy in
9 anticipated Slice-resource deliveries and therefore are compensated by these equal and offsetting
10 costs/credits to the Composite cost pool. See Documentation Table 2.5.6.

11
12 The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are
13 calculated as the greater of the sum of the difference in the T1SFCO between the rate proceeding
14 and the earlier RHWMTier 1 System output, the Non-Slice cost pool will receive a credit for this additional anticipated energy. Alternatively, if the size of the Tier 1
15 System output decreases, the Non-Slice cost pool will be charged for the reduction in anticipated
16 energy. Customers purchasing the Slice/Block product receive either more or less energy in
17 anticipated Slice-resource deliveries and therefore are compensated by these equal and offsetting
18 costs/credits to the Composite cost pool. See Documentation Table 2.5.6.

17 **3.1.4 Rate Design Adjustments Made Between Tier 1 and Tier 2 Cost Pools**

18 **3.1.4.1 Tier 2 Overhead Adjustment**

19 The Tier 2 Overhead Adjustment credits the Composite cost pool for the overhead costs charged
20 to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost Adder, which
21 reflects a proportionate share of BPA's total overhead costs. See section 3.1.7.1. The Tier 2
22 Overhead Adjustment credited to the Composite cost pool is equal to the sum of the Overhead
23 Cost Adders charged to all of the Tier 2 cost pools. The Tier 2 Overhead Adjustment for
24 FY 2014–2015 can be found in Documentation Table 3.2.

1 **3.1.5 PFp Tier 1 Billing Determinants**

2 **3.1.5.1 Tier 1 Cost Allocator**

3 The majority of BPA’s costs to be collected through PF rates are allocated among customers
4 through the TOCA. The TOCA is the customer-specific billing determinant used to collect the
5 costs allocated to the Composite cost pool. A TOCA is calculated for each fiscal year of the rate
6 period for each PFp customer. Each customer’s annual TOCA is calculated as a percentage by
7 dividing the lesser of an individual customer’s RHWMM or its Forecast Net Requirement by the
8 total of the RHWMMs for all PFp customers. The TOCA is a percentage rounded to five decimal
9 places, *i.e.*, seven significant digits.

10
11 The Forecast Net Requirement and RHWMM for the individual customer and the sum of RHWMMs
12 for all customers are expressed in average annual megawatts and rounded to three decimal
13 places. The total of the RHWMMs for all customers can be found in Table 1, and the sum of
14 TOCAs used for FY 2014–2015 can be found in Documentation Table 2.5.6.3.

15
16 **3.1.5.2 Non-Slice TOCA**

17 The Non-Slice TOCA is the billing determinant that is used to collect the costs allocated to the
18 Non-Slice cost pool. A Non-Slice TOCA is calculated for each PFp customer for each year of
19 the rate period. The Non-Slice TOCA is equal to a customer’s TOCA if the customer is
20 purchasing the Load Following or Block product. The Non-Slice TOCA for customers
21 purchasing the Slice/Block product is computed as the difference between the customer’s TOCA
22 and its Slice Percentage. The Non-Slice TOCA percentage is rounded to five decimal places.

23 The forecast sum of Non-Slice TOCAs used for FY 2014–2015 can be found in Documentation
24 Table 2.5.6.3.

1 **3.1.5.3 Slice Percentage**

2 The Slice Percentage is the billing determinant used to collect the costs allocated to the Slice cost
3 pool. A Slice Percentage is calculated for each year of the rate period for each PFp customer
4 purchasing the Slice/Block product. The initial Slice Percentages are in Exhibit J of each Slice
5 customer's CHWM contract. These percentages can be adjusted each year pursuant to
6 section 3.6 of the TRM and reflected in Exhibit K of the customer's CHWM contract. The Slice
7 Percentage is rounded to five decimal places.

8
9 **3.1.5.4 Load Shaping Billing Determinant**

10 The billing determinant for the Load Shaping charge reflects the difference between a customer's
11 actual load served at Tier 1 rates and the customer's annual load reshaped into the
12 monthly/diurnal shape of RHWM Tier 1 System Capability (System Shaped Load). The Load
13 Shaping billing determinant can have either a positive or a negative value.

14
15 A customer's System Shaped Load is calculated as the RHWM Tier 1 System Capability (see
16 section 1.6) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the
17 customer's Non-Slice TOCA. The Load Shaping billing determinants are calculated as the
18 amount of a customer's monthly/diurnal electric load (measured in kilowatthours) to be served at
19 Tier 1 rates minus the customer's System Shaped Load for the same monthly/diurnal period.

20
21 **Monthly/Diurnal RHWM Tier 1 System Capability.** The TRM specifies that the
22 monthly/diurnal shape of the RHWM Tier 1 System Capability will be used to compute the
23 System Shaped Load for purposes of computing Load Shaping billing determinants. The System
24 Shaped Load is not updated if the Tier 1 System output is updated in the rate proceeding. The
25 shape is computed to be constant across both years of the rate period and is the average of each
26 year's respective monthly/diurnal megawatthour amount. In a rate period that does not include a
27 leap year, there will be 24 monthly/diurnal amounts for the RHWM Tier 1 System Capability

1 specified in the GRSPs. In a rate period that includes a leap year, there will be 26 amounts,
2 because each February has a unique value for each HLH and LLH period. See GRSP II.V.

3 4 **3.1.5.5 Demand Billing Determinant**

5 The Demand billing determinant is applicable to customers purchasing the Load Following
6 product, the Block product, and the Block portion of the Slice/Block product. TRM
7 sections 5.3.1 to 5.3.5 contain a detailed explanation of how to calculate the Demand billing
8 determinant. The following is a summary of the TRM explanation.

9
10 Four quantities are used in calculating a PFp customer's Demand charge billing determinant:
11 (1) the Tier 1 Customer's System Peak (CSP); (2) the average amount of a customer's electric
12 load (measured in average kilowatts) that was served at Tier 1 rates during the Heavy Load
13 Hours of a month; (3) the customer's Contract Demand Quantity (CDQ, expressed in kilowatts);
14 and (4) any applicable Super Peak Credit as specified in a customer's CHWM contract.

15
16 The Demand billing determinant is determined by measuring a customer's CSP and then
17 subtracting the other three quantities. The Demand billing determinant calculation can never
18 result in a negative billing determinant. That is, if the calculation results in a value less than
19 zero, the billing determinant is deemed to be zero.

20
21 Tier 1 CSP is equal to a customer's maximum Actual Hourly Tier 1 Load (measured in
22 kilowatts) during the Heavy Load Hours of a month.

23
24 Twelve CDQs are specified for each PFp customer in the customer's CHWM contract.
25
26

1 The Super Peak Credit will be determined pursuant to a customer's CHWM contract. The Super
2 Peak Period hours for FY 2014–2015 are defined in the GRSPs as follows (HE = Hour Ending):

3 October – February HE 8 through HE 10 and HE 18 through HE 20

4 March – May HE 7 through HE 12

5 June – September HE 14 through HE 19

6
7 There are three possible adjustments that may be made to a customer's Demand billing
8 determinant. The first is an adjustment to offset anomalous recovery load peaks that occur after
9 a customer has had power restored to its service territory following a weather-related system
10 outage or other extreme peak event. The second is an adjustment to offset extreme load changes
11 that have severely adversely affected a customer's load factor. The third adjustment would result
12 if the customer retains Provisional CHWM after meeting criteria stated in section 4.1.8 of the
13 TRM. The GRSPs include the calculations for applying these adjustments, applicable qualifying
14 criteria, and notice requirements.

16 **3.1.6 PFp Tier 1 Rates**

17 **3.1.6.1 Tier 1 Customer Rates**

18 Rates for the Composite, Non-Slice, and Slice customer charges are expressed as dollars per one
19 percentage point of billing determinant (TOCA, Non-Slice TOCA, or Slice Percentage,
20 respectively). Each of the three rates is calculated by dividing the total costs allocated to each
21 cost pool by the sum of the respective forecast billing determinants. The quotient of that
22 calculation is then divided by 12 to yield a monthly rate per one percent of the applicable billing
23 determinant.

24
25 The monthly rates for each of the Tier 1 cost pools are shown in Documentation Table 2.5.6.3.
26

1 **3.1.6.2 Tier 1 Load Shaping Rates**

2 The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—for
3 each of 12 months). The Load Shaping rates are set equal to the rate period average marginal
4 cost of power for each monthly/diurnal period as determined in Power Risk and Market Price
5 Study section 2.4. Also see Documentation Table 3.3.

6
7 **3.1.6.2.1 Load Shaping True-Up**

8 The Load Shaping True-Up is an adjustment to the Load Shaping charge that is necessary to
9 ensure that each customer pays a Tier 1 rate for purchases of energy that are less than its
10 RHWM. At the end of each fiscal year for each Load Following customer, BPA will calculate
11 whether a true-up of the Load Shaping charge is applicable. The Load Shaping Charge True-Up
12 applies to a Load Following customer when either its TOCA Load or its Actual Annual Tier 1
13 Load is less than its RHWM. The Load Shaping True-Up rate is the difference between (1) the
14 system-weighted average of the Load Shaping rates and (2) the Composite Customer rate plus
15 the Non-Slice Customer rate, converted to mills per kilowatthour. The process for calculating
16 the Load Shaping True-Up rate is set forth in section 5.2.4.2 of the TRM, and the rate is specified
17 in GRSP I.L.

18
19 **Special Implementation Provision for Load Shaping True-Up.** Special implementation
20 provisions apply if two conditions are met: (1) a customer has Above-RHWM load; and (2) the
21 customer has unused RHWM greater than zero. If these conditions are met, the customer may be
22 eligible for an additional Load Shaping True-Up credit. The amount of the additional Load
23 Shaping True-Up credit will depend on a second calculation.

24
25 This special implementation provision was originally designed to solve a transitional
26 implementation issue caused by setting Above-RHWM load based on a different forecast than is
27 used to determine a customer's TOCA. This provision has a longer-term application, however,

1 because Above-RHWM load is determined in the RHWM Process (prior to the Initial Proposal),
2 and the calculation of a customer's TOCA occurs in the Final Proposal. A consequence of using
3 forecasts prepared at different times is the possibility that a customer has both Above-RHWM
4 load and unused RHWM. This cannot happen if the same forecast is used to set both Above-
5 RHWM load and customers' TOCAs.

6
7 First, if the Annual Deviation calculation of the Load Shaping Charge True-Up is negative or
8 equals zero and the absolute value of the Annual Deviation is less than the customer's Above-
9 RHWM load, then the additional credit is equal to the Load Shaping True-Up rate multiplied by
10 the smallest of (1) the customer's Above-RHWM load, (2) the Above-RHWM load less the
11 absolute value of the Annual Deviation amount, or (3) the Above Forecast amount. Second, if
12 the Annual Deviation calculation of the Load Shaping Charge True-Up is positive and the
13 Annual Deviation amount is less than the Above Forecast amount, then the additional credit is
14 equal to the Load Shaping True-Up rate multiplied by the lesser of (1) the customer's Above-
15 RHWM load or (2) the Above Forecast amount minus the Annual Deviation amount.

16 17 **3.1.6.3 Tier 1 Demand Rates**

18 The Demand rates are based upon the annual fixed costs (capital and O&M) of the marginal
19 capacity resource, an LMS100 combustion turbine, as determined by the Northwest Power and
20 Conservation Council's Microfin model 15.0.1. The Microfin model is used to obtain an
21 estimate for the all-in capital costs in 2014 dollars of an LMS100 with a 2014 in-service date.
22 The all-in capital cost under these specifications is \$1,105/kW. See Documentation Table 3.4.

23
24 The projected debt payment on the \$1,105/kW fixed capital costs is estimated at \$64.21/kW/yr,
25 based on a cost of debt of 4.04 percent financed over 30 years. The plant is assumed to be
26 owned by a publicly owned utility with BPA-backed bonds. The cost of debt is estimated with

1 BPA's FY 2014 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. See FY 2013
2 Interest Rate and Inflation Forecast memo in the Power Revenue Requirements Documentation,
3 chapter 6.

4
5 The cost of fixed O&M included in the Demand rate calculation is obtained from the Microfin
6 model. The calculation of the Demand rate uses the Microfin model's 2006 estimate of
7 \$8/kW/yr escalated to 2014 and 2015 dollars using the 2008 to 2012 average (5-year) rate of
8 1.67 percent calculated from the Implicit Price Deflators from the U.S. Bureau of Economic
9 Analysis. The two-year average annual cost for fixed O&M is \$9.21/kW/yr.

10
11 Insurance and fixed fuel are also included in the calculation of the Demand rate. The average
12 annual insurance cost of \$2.67/kW/yr is calculated based on 0.25 percent of the mid-year
13 assessed value obtained from the Council's Microfin model. The fixed fuel cost assumed in the
14 Demand rate calculation is \$35.69/kW/yr. The fixed fuel cost is estimated using Microfin's
15 vintaged heat rate of 8,650 Btu/kWh applied to the average of the existing and new Pacific
16 Northwest East (PNWE) fixed fuel costs for the applicable fiscal year. An offsetting revenue
17 credit of 10 percent was applied to account for the resale of firm pipeline rights.

18
19 The average annual expense is \$111.77/kW. This annual value is shaped into the 12 months of
20 the year using the shape of the Load Shaping rates, resulting in Demand rates specific to each
21 month. See Documentation Table 3.4 and the Power Rate Schedules, BP-14-A-03-AP01; *e.g.*,
22 Schedule PF-14, section 2.1.2.1.

23 24 **3.1.6.4 PFp Tier 1 Equivalent Rates**

25 The PFp Tier 1 Equivalent rates consist of 12 HLH Energy rates, 12 LLH Energy rates, and
26 12 Demand rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load Shaping rates

1 less a single \$/MWh value. The single \$/MWh value scales the Load Shaping rates to a level at
2 which the PFp Tier 1 Equivalent Energy rates, in conjunction with the demand revenue, would
3 collect the Tier 1 revenue requirement allocated to the PFp Non-Slice loads (the Composite cost
4 pool plus the Non-Slice cost pool). This single \$/MWh value is equivalent to the Load Shaping
5 True-Up rate. This calculation can be found in Documentation Table 2.5.8.5. The Demand rates
6 are equal to the Tier 1 Demand rates.

8 **3.1.7 PFp Tier 2 Cost Pool**

9 There are three Tier 2 rates—the Short-Term rate, the Load Growth rate, and the VR1-2014 rate.
10 Costs allocated to the aggregate Tier 2 cost pool are further allocated to the Short-Term, Load
11 Growth, and VR1-2014 cost pools. For the rate period, those costs are the actual costs associated
12 with the flat-block energy purchases for those rate pools at the transacted amounts and prices,
13 when applicable. Costs for Tier 2 Overhead Adjustment and scheduling services are added to
14 these cost pools and are described in the following sections.

16 **3.1.7.1 Tier 2 Overhead Cost Adder**

17 TRM section 6.3.3 describes an Overhead Cost Adder to be included as part of the Tier 2 rates.
18 The overhead cost components used to calculate the Tier 2 Rate Overhead Cost Adder are listed
19 in Documentation Table 3.2. The rate period total of these overhead costs is divided by BPA's
20 total forecast of revenue-producing energy sales (PFp, IP, NR, FPS, Downstream Benefits and
21 Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services Revenue,
22 and Secondary sales). The result is a \$1.20/MWh adder for the rate period. The \$/MWh value in
23 each year is multiplied by the amount of planned sales in each year for each Tier 2 alternative
24 (Short-Term, Load Growth, and VR1-2014) to produce a dollar value for the Overhead Cost
25 Adder included in each cost pool for each year. The Tier 2 Overhead Cost Adder provides the
26 revenue credit to the Composite cost pool (called Tier 2 Overhead Adjustment); see

1 section 3.1.4.1 above. The specific cost and sales values used in these calculations can be found
2 in Documentation Table 3.5.

3 4 **3.1.7.2 Tier 2 Transmission Scheduling Service Cost Adder**

5 A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS
6 Adder is calculated by dividing the operations scheduling costs for the rate period by the total
7 megawatthours actually scheduled in FY 2011 and FY 2012 to produce a yearly \$/MWh value.
8 This calculation is summarized in Documentation Table 3.6. Inputs to this calculation are
9 included in Documentation Table 3.7. This value is multiplied by the amount of planned Tier 2
10 sales in each year for each Tier 2 alternative (Short-Term, Load Growth, and VR1-2014) to
11 produce the annual cost value for the TSS Cost Adder included in each cost pool for each year.
12 The Tier 2 TSS Cost Adder is one of the credits to the Composite cost pool summed in the
13 Resource Support Services Revenue Credit; see section 3.1.2.1 above. The calculated costs
14 assigned to each cost pool in each year can be found in Documentation Tables 3.8, 3.9, and 3.10.

15 16 **3.1.7.3 Tier 2 BPA Market Purchases**

17 BPA has made three purchases for Tier 2 rate service for the FY 2014–2015 rate period. One
18 was made in FY 2012, and two were made in FY 2013. The purchase costs for the Load Growth
19 and Short-Term cost pools were allocated on a pro rata load basis between the Tier 2 cost pools
20 at the time of each purchase. Any remaining fractional amount of need after the purchases are
21 allocated is priced at the augmentation price.

22
23 In FY 2012, BPA purchased 51 aMW to meet forecast FY 2015 Tier 2 need. The power costs
24 associated with 5 aMW of this purchase were allocated to the Load Growth rate at the time of the
25 purchase. The power costs associated with the remaining 46 aMW were allocated to the
26 VR1-2014 rate. The power amount for VR1-2014 is roughly equal to the Tier 2 load obligation

1 for each year of service associated with this rate plus the real power losses required to deliver the
2 power to the purchasers.

3
4 In FY 2013, BPA purchased 17 aMW to meet forecast FY 2014 Tier 2 need. The power costs
5 associated with 1 aMW of this purchase were allocated to the Load Growth rate at the time of the
6 purchase. The power costs associated with the remaining 16 aMW were allocated to the Short-
7 Term rate to meet the load obligation after accounting for remarketed amounts and additional
8 purchase requirements to cover real power losses required to deliver the power to the purchasers.

9
10 Also in FY 2013, BPA purchased 22 aMW to meet forecast FY 2015 Tier 2 need. The power
11 costs associated with 1 aMW of this purchase were allocated to the VR1-2014 rate at the time of
12 the purchase to meet the real power losses required to deliver the power to purchasers. The
13 power costs associated with the remaining 21 aMW were allocated to the Short-Term rate to
14 meet the load obligation after accounting for remarketed amounts and additional purchase
15 requirements to cover real power losses required to deliver the power to the purchasers. The
16 average megawatt purchase amounts for each rate pool and their associated power purchase
17 prices are summarized in Documentation Table 3.11.

18 19 **3.1.7.3.1 Reallocated Power from the Load Growth Rate Cost Pool**

20 The 5 aMW of power that BPA purchased to meet anticipated need in the Load Growth rate pool
21 is now known to be in excess of the Tier 2 load obligation for FY 2015, as determined in
22 accordance with the RHWM Process, including the real power losses to deliver the power to the
23 purchasers. Pursuant to section 3.4 of the TRM, the power in excess of the cost pool's load is
24 reallocated to another Tier 2 cost pool(s), namely the Short-Term and VR1-2014 cost pools.
25 This allocation was done on a pro-rata basis based on the outstanding need across the pools.

1 For ratemaking purposes, this reallocation of power is at the price at which BPA purchased
2 power to meet its remaining Tier 2 needs in the Short-Term and VR1-2014 cost pools. The rates
3 are computed based on both the actual price of the purchase for that remaining need in the
4 Short-Term and VR1-2014 cost pools and the price of the reallocated power from the Load
5 Growth customer pool. The revenues from such reallocation are credited to the Load Growth
6 cost pool. The cost differential between the power purchase cost and the price associated with
7 the reallocated power is removed from the Load Growth rate and charged to a set of Load
8 Growth rate customers through a Load Growth Rate Customer Billing Adjustment, described in
9 section 3.1.12.

11 **3.1.7.3.2 Reallocated Power from CHWM Contract Section 10 Remarketing**

12 The power purchased in FY 2012 that was assigned to the VR1-2014 rate pool exceeds above-
13 RHW loads for some purchasers. Pursuant to section 6.4 of the TRM and section 10.4 of the
14 CHWM contract, the Tier 2 rate purchase amount in excess of the customer's need is remarketed
15 and the proceeds credited to that customer.

17 Similarly, there are customers with specified resources to which Diurnal Flattening Service
18 (DFS) applies that are in excess of a Customer's Above-RHW load. Pursuant to section 10.5
19 of the CHWM contract, BPA must remarket the amounts of non-Federal resource with DFS in
20 the same manner as it remarkets Tier 2 rate purchase amounts.

22 The power associated with both remarketing actions is reallocated to the Tier 2 Short-Term cost
23 pool. For ratemaking purposes, this reallocation of power is at the price at which BPA purchased
24 power to meet its remaining Tier 2 needs in the Load Growth, Short-Term, and VR1-2014 cost
25 pools. The rates are computed based on both the price of the purchase for that remaining need
26 and the price of the reallocated power from the remarketed VR1-2014 and non-Federal resource

1 with DFS amounts. The revenues from such reallocation are credited to the individual
2 customers, as required under the CHWM contract, as described in sections 3.1.11 and 3.1.15.4.5.
3 Documentation Table 3.12 summarizes the sources of power for meeting the various Tier 2
4 loads. It includes purchases both executed and forecast, remarketed power from other Tier 2 cost
5 pools, and remarketed power from non-Federal resources with DFS.

6 7 **3.1.7.4 Tier 2 Risk Analysis**

8 The risk analysis for Tier 2 rate service is addressed in Power Risk and Market Price Study
9 section 4.3. Consistent with that discussion, no risk mitigation treatment is added to the Tier 2
10 cost pools to cover risks in the FY 2014–2015 rate period.

11 12 **3.1.8 PFp Tier 2 Billing Determinants**

13 The Tier 2 billing determinant is equal to each customer’s commitment to purchase from BPA all
14 or a portion of the customer’s Above-RHWM load. Each customer’s Tier 2 rate service amount
15 is contractually established for FY 2014–2015, and the totals for all the customers by Tier 2
16 alternative are summarized in Documentation Table 3.13. Because there are no purchases of
17 VR1-2014 service in FY 2014 (as service begins in FY 2015), no costs are allocated to the
18 VR1-2014 cost pool for FY 2014.

19 20 **3.1.9 Tier 2 Rates**

21 Based on the annual average megawatt load obligations for each Tier 2 rate alternative (Short-
22 Term, Load Growth, and VR1-2014) in each year and the costs for each cost pool in each year,
23 Tier 2 rates are calculated as summarized in Documentation Tables 3.8, 3.9, and 3.10. Each rate
24 is calculated by dividing the annual costs allocated to the specific Tier 2 cost pool by the billing
25 determinants in that same fiscal year. A specific Tier 2 rate in each year for each Tier 2 rate
26 alternative is necessary because there are different sets of customers associated with each rate,

1 different costs from the separate purchases, different allocations to Tier 2 cost pools, and
2 different surplus/deficit calculations.

3 4 **3.1.9.1 Tier 2 Rate Transmission Curtailment Management Service (TCMS) Adjustment**

5 The Tier 2 rate schedule includes an adjustment for TCMS-related costs. This adjustment will
6 occur if a transmission event (in the form of either a planned transmission outage or a
7 transmission curtailment) has occurred along the transmission path between Mid-C and the BPA
8 point of delivery for the market purchases allocated to the Tier 2 cost pools. The adjustment is
9 described in GRSP II.X.

10 11 **3.1.10 Calculating Charges to Reduce Tier 2 Purchase Amounts**

12 **3.1.10.1 Tier 2 Purchase Amount Reductions for Vintage Rate Service**

13 Section 2.3.1.1 of Exhibit C of the Load Following CHWM contract provides customers with an
14 opportunity to reduce their purchase amounts supplied by BPA at the Tier 2 Short-Term rate and
15 replace them with service from BPA at a Tier 2 Vintage rate if one is offered. For customers
16 making this election, BPA will levy charges to cover costs that BPA is obligated to pay and is
17 not able recover through other transactions. Section 2.3.1.4 of the CHWM contract states that
18 BPA shall determine the costs, if any, to be collected from such charges during the 7(i) process
19 that establishes the applicable Tier 2 Vintage rate. Thirteen customers elected to take service at
20 the VR1-2014 rate, totaling 46 aMW in the FY 2015–2019 period. A portion of these customers
21 did so by electing to reduce their future Short-Term rate purchase amounts. The customer
22 elections were provided prior to the time BPA made any purchases to meet its Short-Term rate
23 load obligations. As a result, there are no costs that need to be recovered through such charges.

1 **3.1.10.2 Tier 2 Purchase Amount Reductions for Service with Non-Federal Resources**

2 Section 2.4.2 of Exhibit C of the Load Following CHWM contract provides customers with an
3 opportunity to reduce the purchase amounts supplied by BPA at the Tier 2 Short-Term rate and
4 replace them with Unspecified Resource Amounts, if notice is provided by October 31 of a rate
5 case year, which was October 31, 2012, for the BP-14 rate period. If a customer makes this
6 election, BPA may levy charges to cover costs that BPA is obligated to pay and is not able to
7 recover through other transactions. Section 2.4.2.1 of the contract states that BPA shall
8 determine the costs, if any, to be collected from such charges during the 7(i) process following a
9 customer's notice to reduce its Tier 2 rate purchase amount. The customers that elected to
10 reduce their Short-Term rate purchase amounts did so for (1) the FY 2014–2015 period,
11 (2) FY 2014 only, or (3) FY 2015 only. The notices were provided prior to BPA making any
12 purchases to meet its Short-Term rate load obligations, so BPA has not incurred any costs due to
13 these purchase reductions; therefore, there are no costs that need to be recovered through such
14 charges.

15
16 **3.1.11 Tier 2 Remarketing for Individual Customers**

17 **3.1.11.1 Tier 2 Remarketing for Load Following Customers**

18 Section 10 of the CHWM contract states that the customer may elect to have BPA remarket its
19 Tier 2 rate purchase amount in the event its Above-RHWM load as forecast for an upcoming rate
20 period year is less than the sum of its Tier 2 rate purchase amounts and New Resource amounts.
21 Notice of such election must be provided by October 31 of a rate case year for Load Following
22 customers. In the BP-14 rate period this provision is applicable to five Load Following
23 customers for VR1-2014 amounts they subscribed to in 2011 that are now in excess of their
24 FY 2015 Above-RHWM loads.

1 **3.1.11.2 Tier 2 Remarketing for Slice/Block Customers**

2 Section 10 of the CHWM contract states that a customer may elect to have BPA remarket its
3 Tier 2 rate purchase amount in the event its Forecast Net Requirement for the first fiscal year of
4 an upcoming rate period is less than the sum of its RHWM and Tier 2 rate purchase amounts.
5 Notice of such election must be provided by August 31 of the applicable fiscal year. In the
6 BP-14 rate period this provision could be applicable in FY 2014 to one Slice/Block customer for
7 the Short-Term rate amount it subscribed to in 2009.

8
9 **3.1.11.3 Calculating the Remarketed Tier 2 Proceeds for Load Following and Slice/Block**
10 **Customers**

11 Section 6.4 of the TRM states that if BPA remarkets a customer's Tier 2 purchase obligation
12 pursuant to the CHWM contract, BPA will credit the proceeds from the remarketing (net of any
13 remarketing costs) to such customer. The customer must continue to pay for the entire purchase
14 at the appropriate Tier 2 rate. The remarketed Tier 2 proceeds are computed for Load Following
15 customers using (1) the remarketed amount of Tier 2 service (in megawatthours) plus real power
16 losses and (2) the actual price BPA paid for the power it purchased to meet its remaining Tier 2
17 need in FY 2015. After notice is provided by a Slice/Block customer, the remarketed Tier 2
18 proceeds will be computed for that customer using (1) the remarketed amount of Tier 2 service
19 (in megawatthours) plus real power losses and (2) the flat annual equivalent market price
20 forecast for the applicable fiscal year plus any additional costs incurred by BPA in purchasing
21 power from other entities. The annual remarketing proceeds for each customer will be divided
22 by 12 to compute a flat monthly credit that will be applied to the customer's bill. Each
23 applicable Load Following customer's forecast monthly remarketed Tier 2 proceeds amount is
24 summarized in Documentation Table 3.14.

1 **3.1.12 Load Growth Rate Customer Billing Adjustment**

2 BPA will apply an adjustment to the bills of Load Growth customers with an Above-RHWM
3 load amount greater than zero and less than 8,760 MWh, as calculated in the RHWM Process.
4 As described in section 3.1.7.3, BPA purchased power in excess of FY 2015 Load Growth rate
5 customer need. This excess power will be allocated to the other Tier 2 cost pools at the price
6 BPA pays for purchases made to meet the remaining Tier 2 load obligation plus losses. In this
7 rate period, the price paid for the power is greater than the remarketing price. The difference is
8 allocated to the Load Growth customers in the form of a charge using their Above-RHWM load
9 amount (if it was computed in the RHWM Process to be greater than zero and less than
10 8,760 MWh) as the cost allocator. A billing cost cap will limit the amount charged to a customer
11 to no more than the second-highest proportion of the applicable customers' forecast Tier 1 bills
12 devoted to this Load Growth rate customer adjustment. The cost differential plus losses is
13 \$53,698. Each applicable Load Growth customer's forecast billing adjustment is summarized in
14 Documentation Table 3.15.

15
16 **3.1.13 PFp Irrigation Rate Discount**

17 The Irrigation Rate Discount is a discount to the PFp Tier 1 rates for eligible irrigation load
18 served by a customer. The discount will appear as a credit on customer bills as an offset to the
19 charge of eligible irrigation load at Tier 1 rates. This discount is available to eligible loads
20 during May, June, July, August, and September during the BP-14 rate period. See GRSP II.K.

21
22 **3.1.13.1 Irrigation Rate Discount Rate**

23 The TRM establishes the method for calculating the Irrigation Rate Discount (IRD) rate. The
24 process begins with a fixed Irrigation Rate Mitigation Program (IRMP) percentage of
25 37.06 percent. See TRM, BP-12-A-03, section 10.3, and BP-12 PRS Documentation, BP-12-FS-
26 BPA-01A, Tables 3.12 and 3.13.

1 The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads will
2 pay through the composite Customer Charge, the Non-Slice Customer Charge, and the Load
3 Shaping Charge, adjusted for any applicable Low Density Discount, divided by the sum of the
4 irrigation loads (expressed in megawatthours), to derive a dollars-per-megawatthour discount.
5 The applicable Low Density Discount is calculated as the weighted average eligible Low Density
6 Discount of irrigation customers, weighted with eligible irrigation loads. See Documentation
7 Table 3.16.

8
9 Forecast revenue for irrigation loads will be calculated using an IRD TOCA derived by dividing
10 the sum of the irrigation loads (expressed in average megawatts) by the sum of all RHWMs. The
11 IRD TOCA will be applied consistent with TRM section 5 for calculation of forecast irrigation
12 revenues from the Composite Customer Charge, the Non-Slice Customer Charge, and the Load
13 Shaping Charge. This discount will be seasonally available to qualifying loads during May,
14 June, July, August, and September. See TRM, BP-12-A-03, at 93. The calculation is shown on
15 Documentation Table 2.3.3.

17 **3.1.13.2 Irrigation Rate Discount Bill Credit**

18 The irrigation credit available to a customer with eligible irrigation load is equal to the monthly
19 irrigation load set forth in Exhibit D of the customer's CHWM contract multiplied by the IRD
20 rate. The amount of irrigation credit the customer will receive is limited to the lesser of a
21 customer's Tier 1 energy purchase or its eligible irrigation load amounts in the customer's
22 CHWM contract.

24 **3.1.13.3 Irrigation Rate Discount True-Up**

25 At the end of each irrigation season, customers with eligible irrigation load will send BPA their
26 measured May through September irrigation load amounts. If BPA determines that the measured

1 irrigation load amounts are less than the eligible irrigation load amounts set forth in Exhibit D of
2 the customer's CHWM contract, then the purchaser shall reimburse BPA for the excess IRD
3 credits. Excess IRD credits will be calculated as the IRD rate multiplied by the difference
4 between the contract irrigation load and the measured irrigation load. See GRSP II.K.3.
5

6 **3.1.14 PFp Melded Rates (Non-Tiered Rate)**

7 Melded PF Public rates are included in the PF rate schedule. The PFp Melded rates consist of
8 12 HLH Energy rates, 12 LLH Energy rates, and 12 Demand rates. The PFp Melded Energy
9 rates are equal to the PFp Load Shaping rates less a single \$/MWh value. The single \$/MWh
10 value adjusts the Load Shaping Rates so that the PFp Melded Energy rates, in conjunction with
11 the demand revenue, do not collect more or less revenues than the Tier 1 and Tier 2 revenue
12 requirement allocated to the PFp loads. The \$/MWh value is the PFp Melded Equivalent Energy
13 Scalar, which is also used in the Slice True-Up to determine the actual DSI revenue credit.
14 Calculation of the scalar is shown in Documentation Table 2.5.8.2. The applicable Demand rates
15 are equal to the PFp Tier 1 Demand rates.
16

17 The PFp Melded Energy rates are also used to shape and set the level of the IP Energy rates, as
18 described in section 3.3.1.
19

20 **3.1.15 PFp Resource Support Services**

21 BPA offered customers access to RSS and related services for their variable, non-dispatchable
22 non-Federal resources, in accordance with the CHWM contract. The related services include
23 Transmission Scheduling Service and Transmission Curtailment Management Service. In
24 general, these services are designed to financially convert a variable, non-dispatchable resource
25 into a flat annual block of power or the specified monthly/diurnal resource shape found in

1 Exhibit A of the customer's CHWM contract. Resource Remarketing Service (RRS) is an
2 additional related service that will be provided during the BP-14 rate period.

3
4 RSS is also applied to Federal resource acquisitions to make them financially equivalent to a flat
5 block, if necessary. See TRM section 8. The cost of Klondike III, a wind plant, is assigned to
6 Tier 1 Augmentation in the Composite cost pool. Tier 1 Augmentation is assumed to be in the
7 shape of an annual flat block purchase for ratemaking purposes. See TRM section 3.5. Because
8 Klondike III's generation is variable and non-dispatchable in nature, certain RSS rate design
9 components apply to Klondike III, and the resulting costs are allocated to the Composite cost
10 pool. These costs are described below.

11
12 Costs for RSS are not allocated to the Tier 2 cost pools because there are no variable,
13 non-dispatchable resources assigned to the Tier 2 cost pools. Costs for TSS are allocated to
14 the Tier 2 cost pools, as described in section 3.1.7.2. Costs for TCMS events associated with
15 Tier 2 rate service are recovered through the Tier 2 Rate TCMS Adjustment, described in
16 section 3.1.9.1.

17 18 **3.1.15.1 RSS Rates**

19 RSS rates are included in the PF and FPS rate schedules. The RSS rates relevant to the PFp rates
20 include Diurnal Flattening Service energy and capacity rates, Resource Shaping rates and
21 adjustment, Secondary Crediting Service shortfall and secondary energy rates, and Secondary
22 Crediting Service Administrative Fee rate. The RSS rates relevant to the FPS rate include
23 Forced Outage Reserve Service energy and capacity rates, TSS rate, TCMS rate, and RRS. In
24 total, about \$3 million of forecast RSS and TSS-related revenue credits are applied annually to
25 the Tier 1 cost pools. See Documentation Tables 3.1 and 3.5.

1 **3.1.15.2 RSS Diurnal Flattening Service, Resource Shaping Charge, and Resource Shaping**
2 **Charge Adjustment**

3 **3.1.15.2.1 Diurnal Flattening Service**

4 DFS is an optional service that financially converts the output of a variable, non-dispatchable
5 resource into one that is equivalent to a flat amount of power within each diurnal period of a
6 month. When DFS charges are coupled with the Resource Shaping Charges, the variable output
7 of a generating resource is financially converted to a flat annual block of power. BPA selected a
8 flat annual block of power as the benchmark shape to which to compare new non-Federal
9 resources and Tier 2 purchases. DFS will apply to the non-Federal resource the customer is
10 applying to its load and any portion of the resource remarketed by BPA.

11
12 The RSS module of RAM calculates a unique set of rates and charges for each resource to which
13 DFS is applied. Included in the Documentation are the final rates and charges calculated for the
14 customers that have requested DFS for their resources. See Documentation Table 3.17. PF-14
15 rate schedule sections 5.1 and 5.2 describe the general rate application of the DFS-related
16 charges. The GRSPs include the calculations for the DFS capacity charges, DFS energy charges,
17 and Resource Shaping charges for the resources to which DFS is applied. See GRSP II.U.

18
19 Briefly, DFS charges include the following elements:

- 20 • A DFS capacity charge based on the PFp Tier 1 Demand rate applied to the difference
21 between the calculated firm capacity of the resource and the planned average HLH
22 generation of the resource. This charge reflects the costs of reserving an amount of
23 capacity to smooth the variable generation of a resource into a flat block of power.
- 24 • A DFS energy charge based on the potential cost of storing and releasing power using
25 a resource capable of storing energy (pumped storage) to balance the hourly shape of
26 the resource to which DFS is applied. This charge reflects the costs of energy storage
27 to smooth the hourly generation variation into a flat monthly/diurnal block of power.

1
2 When DFS is applied to a resource, other charges must be added to the DFS charges to complete
3 the financial conversion to a flat annual block of power. These include the following elements:

- 4 • The Resource Shaping charge, based on the Resource Shaping rates (which are equal
5 to the PFp Tier 1 Load Shaping rates) to financially convert the resource amounts that
6 have been flattened on a monthly/diurnal basis into a flat annual block of power.
- 7 • A Resource Shaping Charge Adjustment, based on the Resource Shaping rates, to
8 correct for generation forecast error.

9
10 **3.1.15.2.2 DFS Capacity Charge**

11 Unless stated otherwise, the resource amounts used in these calculations are either (1) generation
12 amounts specified in the customer's CHWM contract Exhibit A (Exhibit A amounts) or
13 (2) planned generation amounts based on hourly generation from the most recent historical year
14 specified in the customer's CHWM contract Exhibit D (Exhibit D amounts).

15
16 **DFS Capacity Rate.** The rates used to calculate the DFS Capacity Charge are the monthly PFp
17 Tier 1 Demand rates.

18
19 **DFS Capacity Billing Determinant.** The billing determinant is the difference between the
20 resource's monthly average HLH Exhibit D amounts in one year and the calculated monthly firm
21 capacity of the resource.

22
23 **Monthly Firm Capacity.** The RSS module of RAM calculates monthly firm capacity amounts
24 for each resource. This calculation represents the lowest level of historical generation in a HLH
25 period for each month after accounting for planned and forced outages. The firm capacity of a
26 resource is calculated as the percentile equal to the forced outage rating calculated from the

1 historical monthly HLH generation levels. In other words, a resource with a 5 percent forced
2 outage rating would have a firm capacity amount equal to the 5th percentile of the hourly
3 historical generation amounts for the HLH period of a month.

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

17
18 **DFS Capacity Charge.** For each resource, the DFS Capacity charge is the lesser of:

- 19 (1) the sum of (i) the monthly DFS Capacity rates multiplied by (ii) the
20 monthly DFS billing determinants
21 or
22 (2) the annual average Exhibit D amount multiplied by the sum of the
23 monthly PF Tier 1 Demand rates
24
25
26

1 The result is then divided by 12 to calculate a flat monthly charge that will be specified in
2 Exhibit D of the customer's CHWM contract. Documentation Table 3.17 shows the individual
3 DFS capacity charges that are calculated for the individual resources to which DFS is applied.
4

5 **3.1.15.2.3 DFS Energy Charge**

6 **DFS Energy Rate.** A unique DFS energy rate is developed for each resource to which DFS is
7 applied. The purpose of this rate is to reflect the potential cost of storing and releasing energy to
8 offset the hourly variability of the resource's Exhibit D amounts. The RSS module of RAM
9 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period in
10 a year, the sum of planned generation in excess of average monthly/diurnal Exhibit D amounts is
11 multiplied by 25 percent (to reflect the energy lost when using a pumped storage hydroelectric
12 unit to perform the energy storage). The result is multiplied by the applicable monthly/diurnal
13 Resource Shaping rate. The monthly/diurnal results are summed for the year and divided by the
14 total planned energy from the Exhibit D amounts to calculate the DFS Energy rate.
15

16 **DFS Energy Billing Determinant.** The DFS energy billing determinant is the total actual
17 generation for the particular resource during the billing month. The actual generation amounts
18 will be either the resource meter readings, or the resource transmission schedules if the resource
19 requires an e-Tag. For wind resources within the BPA balancing authority area, transmission
20 curtailments associated with Dispatcher Standing Order (DSO) 216 will be treated as reduced
21 scheduled amounts when calculating the actual generation for such resources.
22

23 **DFS Energy Charge.** The DFS energy charge is the product of multiplying the DFS energy rate
24 by the DFS energy billing determinant for each month. Documentation Table 3.17 shows the
25 DFS energy rates that are calculated for the individual resources to which DFS is applied.

1 GRSP II.U.1.(a) includes the formula for calculating the DFS energy charges for the individual
2 resources to which DFS is applied.

3 4 **3.1.15.2.4 Resource Shaping Charge**

5 **Resource Shaping Rate.** The monthly/diurnal Resource Shaping rates are equal to the PFp
6 Tier 1 Load Shaping rates. The purpose of this rate is to reflect the value of buying and selling
7 flat monthly/diurnal blocks of power in the market (with the Load Shaping rate as the proxy
8 market price) to convert a diurnally flat resource within the month into one that, on a planned
9 basis, is flat across the year.

10
11 **Resource Shaping Billing Determinant.** The Resource Shaping billing determinant for each
12 resource is the difference between the planned monthly/diurnal generation from the Exhibit D
13 amounts and the annual average generation from the Exhibit A amounts for the same year.

14
15 **Resource Shaping Charge.** For each resource, the Resource Shaping charge is the product of
16 multiplying the Resource Shaping rate by the Resource Shaping billing determinant. The sum of
17 the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat
18 monthly charge. On a monthly basis this calculation can result in a charge or a credit.

19
20 The flat monthly Resource Shaping charge that results from this calculation will be reflected on
21 the customer's monthly bill. Documentation Table 3.17 shows the Resource Shaping charges
22 that are calculated for the individual resources to which DFS is applied. GRSP II.U.1.(c)
23 includes the formula for calculating the Resource Shaping charges for the individual resources to
24 which DFS is applied.

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

6 **3.1.15.2.5 Resource Shaping Charge Adjustment**

7 **Resource Shaping Charge Adjustment Rate.** The rates used to calculate the Resource Shaping
8 Charge Adjustment are the monthly/diurnal Resource Shaping rates.

9
10 **Resource Shaping Charge Adjustment Billing Determinant.** For each resource, the billing
11 determinant is the difference between the planned monthly/diurnal generation from CHWM
12 contract Exhibit D amounts and the actual monthly/diurnal generation of the resource. The
13 actual generation amounts will be either the resource meter readings, or resource transmission
14 schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge
15 Adjustment billing determinant will also include energy provided through Forced Outage
16 Reserve Service (FORS), TCMS, planned outage replacement, economic dispatch, and
17 Unauthorized Increases in the determination of actual generation. For wind resources within the
18 BPA balancing authority area, transmission curtailments associated with DSO 216 will be treated
19 as reduced scheduled amounts when calculating the actual generation for such resources.

20
21 **Resource Shaping Charge Adjustment.** For each resource, the Resource Shaping Charge
22 Adjustment is the product of multiplying the Resource Shaping rate by the Resource Shaping
23 Charge Adjustment billing determinant for each monthly/diurnal period. The purpose of this
24 adjustment is to capture the cost or value of the energy differences between the Exhibit D
25 amounts and the actual generation of the resource. This adjustment completes the financial
26 conversion to a flat annual block of power by making up for any energy cost differences between

1 planned and actual generation amounts. On a monthly/diurnal basis this calculation can result in
2 either a charge or a credit. GRSP II.U.1.(d) includes the formula for calculating the Resource
3 Shaping Charge Adjustment for the individual resources to which DFS is applied.

4 5 **3.1.15.2.6 DFS and Resource Shaping Charge Application to Tier 1 Augmentation**

6 TRM section 8 states that RSS pricing will be used to make certain Federal resource acquisitions
7 financially equivalent to a flat block. TRM section 3.5 states that Tier 1 Augmentation is
8 assumed to be in the shape of an annual flat block purchase for ratemaking purposes. The costs
9 of Klondike III, a wind resource, are allocated to Tier 1 Augmentation. The RSS module of
10 RAM calculates a DFS capacity charge, DFS energy charge, and Resource Shaping charge for
11 Klondike III. The billing determinant for the DFS energy charge is the planned generation
12 amount based on the historical generation year data, in lieu of actual generation data. In
13 addition, the RSS module calculates a TSS charge for Klondike III. The sum of the charges for
14 Klondike III for each year is allocated to the Tier 1 Composite cost pool under the
15 “Augmentation RSS and RSC Adder” line item. There is no Resource Shaping Charge
16 Adjustment applied to Klondike III. Documentation Table 3.17 shows the summary DFS,
17 Resource Shaping, and TSS charges that are calculated for Klondike III.

18 19 **3.1.15.3 RSS Secondary Crediting Service (SCS)**

20 SCS provides a credit or charge to a Load Following customer that dedicates to its load its entire
21 share of the output of a hydroelectric Existing Resource. The customer will receive a credit for
22 the energy produced by that resource that is in excess of the monthly/diurnal amounts specified
23 in the CHWM contract Exhibit A. The additional generation would increase BPA’s revenues
24 because of the increased secondary energy BPA can market or would lower BPA’s costs because
25 of reduced balancing purchases. The customer will receive a charge for any energy shortfall by
26 the resource from the monthly/diurnal Exhibit A amounts, because BPA’s secondary revenues

1 would be lower or BPA's balancing costs would be higher. If a customer does not take this
2 service, it must apply the exact Exhibit A amounts to its load, unless the resource is a small,
3 non-dispatchable resource.

4
5 The PF-14 rate schedule includes a section on the rate application of the SCS-related charges or
6 credits. GRSP II.U.2 includes the formulas for calculating the SCS charges or credits for the
7 resources to which SCS is applied. Documentation Table 3.17 includes the individual SCS
8 Administrative Charges for the individual non-Federal resources to which SCS is applied.

9 10 **3.1.15.3.1 SCS Pricing Summary**

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

- 14 • A Secondary Energy credit or Shortfall Energy charge, priced at the Resource
15 Shaping rate.
- 16 • An Administrative Charge, similar to a reservation fee, based on the forced outage
17 rating of the hydro resource, the PFp Tier 1 Demand rate, and the monthly HLH
18 Exhibit A amounts.

19 20 **3.1.15.3.2 SCS Shortfall Energy Charges and Secondary Energy Credits**

21 **SCS Energy Rate.** The rates used to calculate the SCS Shortfall Charge and the Secondary
22 Energy Credit are the monthly/diurnal Resource Shaping rates.

23
24 **SCS Billing Determinant.** For each resource, the billing determinant is the difference between
25 the actual monthly/diurnal generation and the monthly/diurnal generation from Exhibit A
26 amounts. The actual generation amounts will be either the resource meter readings, or resource

1 transmission schedules if the resource requires an e-Tag. For SCS Option 1 only (the power
2 exchange between the customer and BPA), the actual generation amounts shall be net of
3 transmission losses on the BPA transmission system. See GRSP III.A.15. The actual generation
4 shall include energy amounts provided through TCMS.

5
6 **SCS Shortfall Energy Charge/Secondary Energy Credit.** For each resource, the charge or
7 credit is the product of multiplying the SCS energy rate by the SCS energy billing determinant
8 for each monthly/diurnal period. If the actual generation exceeds the Exhibit A amount, the
9 customer will receive a credit. If the actual generation is less than the Exhibit A amount, the
10 customer will receive a charge. GRSP II.U.2.(a) includes the formula for calculating the SCS
11 Shortfall Energy Charges/Secondary Energy Credits for the individual resources to which SCS is
12 applied.

13 14 **3.1.15.3.3 SCS Administrative Charge**

15 A customer's SCS Administrative Charge will be calculated in the form of a capacity reservation
16 fee. This capacity reservation fee's structure mirrors the structure of the FORS capacity charge,
17 described in section 3.5.1.

18
19 **SCS Administrative Rate.** The rates used to calculate the SCS Administrative Charge are the
20 monthly PFp Tier 1 Demand rates.

21
22 **SCS Administrative Charge Billing Determinant.** For each resource, the billing determinant
23 is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

24
25 **SCS Administrative Charge.** For each resource, the SCS Administrative charge is the product
26 of multiplying the SCS Administrative rate by the SCS Administrative billing determinant for

1 each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The flat
2 monthly SCS Administrative charge that results will be specified in section 2.5.3.2 of Exhibit D
3 of the CHWM contract. Documentation Table 3.17 shows the SCS Administrative charges that
4 are calculated for the individual resources to which SCS is applied. GRSP II.U.2.(b) includes the
5 formula for calculating the SCS Administrative Charge for the individual resources to which
6 SCS is applied.

8 **3.1.15.4 Additional PFp RSS Considerations**

9 **3.1.15.4.1 Forced Outage Rating**

10 Each generally recognized type of generating resource has a standard forced outage rating. This
11 rating represents the average percentage of time that a generating resource is unavailable for load
12 service due to unanticipated breakdown. BPA uses a minimum 5 percent forced outage rating
13 for hydroelectric resources, 7 percent for thermal resources, and 10 percent for all other
14 resources. Customers taking services that have charges including the use of a forced outage
15 rating may request that BPA increase the forced outage rating for their resource, and those with a
16 resource other than a hydroelectric resource may request that BPA decrease the forced outage
17 rating to as low as seven percent.

19 **3.1.15.4.2 Historical Generation Year Resource Amounts Adjusted for Schedules**

20 Typically, the RSS module of RAM will use scheduled amounts for resources that require an
21 e-Tag and meter amounts for “behind-the-meter resources.” However, for small resources or
22 small shares of a resource, BPA may apply a meter amount instead of a schedule amount for
23 purposes of pricing RSS if the meter amount produces lower RSS rates and charges. This
24 adjustment applies to both RSS provided under the PF rate schedule, discussed above, and the
25 FPS rate schedule, described below.

1 **3.1.15.4.3 Credits to the PFp Tier 1 Customer Cost Pools**

2 Forecast revenue credits will be calculated from the RSS charges. All revenues except those
3 from the Resource Shaping Charge will be credited to the Composite cost pool. The forecast
4 revenue from the Resource Shaping Charge sales is a revenue credit to the Non-Slice cost pool.
5 Additional information on these revenue credits is found in sections 3.1.2.1 and 3.1.2.2.
6

7 **3.1.15.4.4 Non-Federal Resource with DFS Remarketing**

8 Section 10 of the CHWM contract states that the customer may elect to remove a new
9 non-Federal resource in the event its Above-RHWM load, as forecast for an upcoming rate
10 period year, is less than the sum of its Tier 2 rate purchase amounts and New Resource amounts.
11 Notice of such election must be provided by October 31 of a rate case year for Load Following
12 customers. Section 10.5 of the CHWM contract states that BPA shall remarket the amounts of
13 removed resources for which the customer purchases DFS in the same manner BPA remarkets
14 Tier 2 rate purchase amounts. The customer will continue to pay for DFS on the entire resource
15 amount that is applied to load and any portion of the resource remarketed by BPA. In the BP-14
16 rate period this provision is applicable to three Load Following customers for non-Federal
17 resource amounts they previously dedicated to load and that are now in excess of their FY 2014
18 or FY 2015 Above-RHWM loads.
19

20 **DFS Remarketing Rate.** The DFS remarketing proceeds are computed for Load Following
21 customers using the actual price BPA paid for the power it purchased to meet its remaining
22 Tier 2 load obligation plus losses in the applicable fiscal year.
23

24 **DFS Remarketing Billing Determinant.** For each applicable non-Federal resource to which
25 DFS applies, the billing determinant is (i) the Customer's total non-Federal resource, less (ii) the
26 amount of the Customer's non-Federal resource needed to meet Above-RHWM load, as reflected
27 in the customer's CHWM contract Exhibit A, when updated.

1 **DFS Remarketing Credit.** For each resource, the DFS remarketing credit will be the product of
2 multiplying the DFS remarketing rate by the DFS remarketing billing determinant for each
3 applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly
4 credit. Documentation Table 3.18 shows the forecast monthly DFS Remarketing Credits that are
5 calculated for the individual resources to which the DFS remarketing is applied.

6 7 **3.2 Priority Firm Exchange Rate Design**

8 The PFX rate applies to participants in the Residential Exchange Program for sales of exchange
9 energy pursuant to a Residential Purchase and Sale Agreement (RPSA) or a REP Settlement
10 Implementation Agreement (REPSIA). Under either an RPSA or REPSIA, the PFX rate is
11 applied to BPA's sales of exchange energy, and the participating utility's ASC is applied to
12 BPA's purchase of exchange energy, where the exchange energy is equal to the utility's eligible
13 residential and farm load. The difference between the amount BPA pays for exchange
14 "purchases" and the amount BPA receives for exchange "sales" determines the amount of
15 monetary REP benefits BPA pays the utility. The PFX rate also applies to any actual power sales
16 to exchanging utilities under contractual "in-lieu" provisions.

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

24
25 The two Base PFX rates are computed within RAM based on the average PF rate immediately
26 prior to the determination of section 7(b)(2) rate protection. At this point in the ratemaking

1 process, no 7(b)(2) rate protection has been determined, so the Base PFX rates bear no rate
2 protection costs. The PFX rate applicable to IOUs (and any eligible COU without a CHWM
3 contract) is computed by dividing all costs allocated to the PF rate pool by all PF rate pool loads
4 and then adding a transmission charge for delivering the exchange power to the customer. The
5 PFX rate applicable to COUs with CHWM contracts is calculated in the same manner, except that
6 the costs allocated to Tier 2 cost pools are excluded from the numerator, and loads served at
7 Tier 2 rates are excluded from the denominator.

8
9 Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of
10 providing 7(b)(2) rate protection continues to be assessed, but the surcharge for IOUs also
11 includes the allocation of the costs of Refund Amounts. See section 2.2.1.3. The amount of
12 7(b)(2) rate protection costs allocated to the PFX rates is allocated to each REP participant on a
13 pro rata basis using REP benefits calculated using the Base PFX rates (Unconstrained Benefits)
14 as the allocator. The cost of Refund Amounts is allocated to each IOU using IOU Unconstrained
15 Benefits as the allocator. The total amount allocated to each REP participant is divided by the
16 participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

17
18 For each REP participant, the applicable Base PFX rate is added to its utility-specific
19 7(b)(3) surcharge to determine its utility-specific PFX rate. For each month of the rate period, the
20 participant will submit to BPA its exchange load for the prior month. BPA will multiply this
21 invoiced exchange load by the difference between the participant's ASC and its PFX rate to
22 calculate the amount of REP benefits payable to the participant. See Documentation
23 Table 2.4.11.

24
25 For an overview of the BP-14 Final Proposal Tiered PF Rates for FY 2014–2015, see Study
26 Table 2.

1 **3.3 Industrial Firm Power (IP) Rate Design**

2 **3.3.1 IP Energy Rates**

3 The IP rate design includes 24 monthly/diurnal Energy rates, two for each month, one each for
4 HLH and LLH. Monthly and diurnal differentiation of IP Energy rates is performed based on the
5 HLH and LLH differentiation of the PFp Melded rate (see section 3.1.14).

6
7 IP Energy rates are determined by adjusting the PFp Melded rates by the Value of Reserves
8 (VOR) credit for operating reserves provided by the DSI load, the typical industrial margin, and
9 a REP surcharge. See Documentation Table 2.5.8.3.

10
11 **3.3.1.1 IP Adjustment for Value of Reserves Provided**

12 A VOR credit is included in the IP rate, as provided in section 7(c)(3) of the Northwest Power
13 Act. See section 1.2.2. The FY 2014–2015 rate period DSI power sales forecast is 312 aMW for
14 both years. See Power Loads and Resources Study section 2.4. Based on provisions of DSI
15 contracts currently in place, these power sales are assumed to provide interruption reserve rights
16 (operating reserves) to BPA, and therefore the IP rate includes a VOR credit.

17
18 The first step for valuing operating reserves provided by DSIs is to determine a marginal price
19 for these reserves. Because the DSI-supplied reserves are used to meet BPA’s reserve
20 obligations, the cost of Operating Reserves – Supplemental is used to establish the marginal
21 value.

22
23 The second step in valuing the DSI reserves is to determine the quantity of reserves provided.
24 To calculate this quantity, the total DSI load is reduced to account for wheel-turning load that
25 cannot be curtailed. The wheel-turning load is forecast to be 6 aMW. The interruption reserves
26 provided are 10 percent of the remaining DSI load (306 MW), or 30.6 MW.

1 The VOR credit included in the IP-14 rate is 0.975 mills/kWh. See Documentation Table 2.4.1
2 for calculation of the value of DSI reserves.

3.3.1.2 IP Rate Typical Margin

5 Another component of the IP rate is the typical margin, as provided in section 7(c)(2) of the
6 Northwest Power Act. See section 1.2.2. The typical margin is based generally on the overhead
7 costs that COUs add to the cost of power in setting their retail industrial rates. The typical
8 margin included in the IP-14 rate is 0.709 mills/kWh. The methods and calculations used to
9 determine the typical margin are discussed in Appendix A.

3.3.1.3 REP Surcharge

12 The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest
13 Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be
14 allocated to all other power sold, which includes power sold at the IP rate. See section 1.2.2.
15 The cost of rate protection allocated to the IP rate is determined pursuant to the 2012 REP
16 Settlement and is included in the IP-14 rate. The IP-14 REP Surcharge is 7.69 mills/kWh. See
17 Documentation Table 2.4.14 for calculation of the REP Surcharge.

3.3.2 IP Demand Rates

20 The Demand rates for the IP rate schedule are equal to the PFp Demand rates, as described in
21 section 3.1.6.3.

23 As with the PFp Demand charge, the IP Demand billing determinant is applied to only a portion
24 of the DSI peak demand placed on BPA. The IP Demand billing determinant in each billing
25 month will be equal to the DSI's highest HLH schedule, or metered amount, minus the average
26 HLH schedule amount, or metered amount, less any applicable Industrial Demand Adjuster.

1 The Industrial Demand Adjuster is a monthly quantity of demand (expressed in kilowatts) that is
2 subtracted from the hourly peak schedule amount when calculating the IP Demand billing
3 determinant. Power Rate Schedules, BP-14-A-03-AP01, *e.g.*, Schedule IP-14, section 2.2.2.
4

5 **3.4 New Resources (NR) Rate Design**

6 **3.4.1 NR Energy Rates**

7 Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and LLH
8 differentiation of the PFp Load Shaping rates. See Documentation Table 2.5.8.4.
9

10 The NR energy rates are determined by adjusting each PFp Load Shaping rate by an equal scalar
11 until the NR energy rates recover the allocated NR revenue requirement minus the forecast
12 Demand charge revenue. See Documentation Table 2.5.8.4.
13

14 After the scaling process is complete, a REP Surcharge is added to each of the monthly/diurnal
15 energy rates. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate
16 protection afforded to preference customers be allocated to all other power sold, which includes
17 power sold at the NR rate. See section 1.2.2. The cost of rate protection allocated to the NR rate
18 is determined pursuant to the 2012 REP Settlement. The NR-14 REP Surcharge is
19 7.69 mills/kWh. See Documentation Table 2.4.14 for calculation of the REP Surcharge.
20

21 **3.4.2 NR Demand Rates**

22 The Demand rates for the NR rate schedule are equal to the PFp Demand rates, as described in
23 section 3.1.6.3.
24

25 As with the PFp Demand charge, the NR Demand billing determinant is only a portion of the
26 peak demand placed on BPA. The NR Demand billing determinant will be equal to the highest

1 NR Hourly Load during HLH less the average hourly HLH energy purchased in that particular
2 month at the NR energy rates.

3.4.3 NR Energy Shaping Service for New Large Single Loads

3
4
5 The NR Energy Shaping Service is offered to Load Following customers that need a service that
6 shapes a dedicated resource serving a New Large Single Load (NLSL) to the actual load of the
7 NLSL. The service credits or debits the customer for the difference between the dedicated
8 resource amount during a monthly diurnal period and the measured NLSL load during that same
9 monthly diurnal period. A True-Up is applied at the end of each fiscal year to ensure that any net
10 positive power purchased from BPA at the NR Energy Shaping rates is paid for at the applicable
11 NR energy rate.

3.4.3.1 NR Energy Shaping Rates

12
13
14 The NR rate schedule includes 24 Energy Shaping rates (two diurnal periods—HLH and LLH—
15 for each of 12 months) applicable to the NR Energy Shaping Service. The Energy Shaping rates
16 are set equal to the rate period average marginal cost of power for each monthly/diurnal period as
17 determined in Power Risk and Market Price Study section 2.4. See Documentation Table 3.3.

3.4.3.2 NR Energy Shaping Billing Determinant

18
19
20 There are two energy billing determinants each month, one for the HLH and one for the LLH.
21 Each monthly energy billing determinant is equal to the measured NLSL load during the
22 monthly/diurnal period minus the dedicated resource amount serving that load during that same
23 monthly diurnal period. The billing determinant for any period can be negative.

1 **3.4.3.3 NR Energy Shaping Service True-Up**

2 The NR Energy Shaping Service True-Up is an adjustment to the NR Energy Shaping Service
3 that will ensure that each customer pays the NR rate for BPA energy that the customer used to
4 serve an NLSL. At the end of each fiscal year, BPA will calculate the NR Energy Shaping
5 Service True-Up by netting the billing determinants for the fiscal year. If the amount is greater
6 than zero, the amount is multiplied by the rate specified in GRSP II.G.

7
8 **3.5 Firm Power Products and Services Rate Design, Resource Support Services,
9 and Transmission Scheduling Service**

10 Products and services available under the FPS rate schedule are described in BPA’s BP-14
11 Power Rate Schedules, BP-14-A-03-AP01, section FPS-14. Sales under this rate schedule are
12 discretionary; BPA is not obligated to sell any of these products, even if such sales will not
13 displace PF, NR, or IP sales. Products priced under the FPS-14 rate schedule may be sold at
14 market-based or negotiated rates, which may have a demand component, an energy component,
15 or both. Applicable transmission rates will apply to the extent required to purchases of firm
16 power under the FPS-14 rate.

17
18 The FPS-14 rate schedule provides for seven products and services: (1) Firm Power and Capacity
19 Without Energy; (2) Supplemental Control Area Services; (3) Shaping Services; (4) Reservations
20 and Rights to Change Services; (5) Reassignment or Remarketing of Surplus Transmission
21 Capacity; (6) Services for Non-Federal Resources; and (7) Unanticipated Load Service.

22
23 **3.5.1 Firm Power and Capacity Without Energy**

24 When available, BPA sells firm power, including secondary energy or firm capacity, for use
25 within the Pacific Northwest and outside the Pacific Northwest. Such power sales are made
26 under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually
27 agreed by BPA and the customer. Sales of firm power may be subject to a REP Surcharge. The

1 applicability of a REP Surcharge will be made by BPA at the time of the sale, as set forth in the
2 2012 REP Settlement Agreement.

3 4 **3.5.2 Supplemental Control Area Services**

5 BPA sells supplemental control area services, when available, for use within the Pacific
6 Northwest and outside the Pacific Northwest. Such services are sold under the FPS rate schedule
7 at rates and billing determinants specified by BPA or as mutually agreed by BPA and the
8 customer.

9 10 **3.5.3 Shaping Services**

11 BPA sells shaping services, when available, for use within the Pacific Northwest and outside the
12 Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing
13 determinants specified by BPA or as mutually agreed by BPA and the customer.

14 15 **3.5.4 Reservations and Rights to Change Services**

16 BPA offers reservations of power and services, when available, and the rights to change sales
17 and services for use within the Pacific Northwest and outside the Pacific Northwest. Such
18 services are sold under the FPS rate schedule at rates and billing determinants specified by BPA
19 or as mutually agreed by BPA and the customer.

20 21 **3.5.5 Reassignment or Remarketing of Surplus Transmission Capacity**

22 Power Services reassigns or remarkets its surplus transmission capacity, when available, that has
23 been purchased from a transmission provider, including Transmission Services, consistent with
24 the terms of the transmission provider's Open Access Transmission Tariff. Power Services sells
25 this surplus transmission capacity to parties within the Pacific Northwest and outside the Pacific

1 Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants
2 specified by BPA or as mutually agreed by BPA and the customer.

3 4 **3.5.6 Services for Non-Federal Resources**

5 BPA is offering Forced Outage Reserve Service and Transmission Scheduling Service at posted
6 FPS rates. FORS is one of the Resource Support Services and is offered under the FPS rate
7 schedule to customers with resources that meet specific requirements specified in the CHWM
8 contract. For customers without CHWM contracts, FORS would be offered, if available, under
9 the Reservations and Rights to Change Services part of the FPS rate schedule. Further
10 information is provided in section 3.5.6.1 below.

11
12 TSS is not a Resource Support Service but is related to the services that comprise RSS and is
13 being offered under the FPS rate schedule. It is a required service for customers with resources
14 that meet eligibility requirements specified in the CHWM contract. Further details on TSS and
15 TCMS are provided in section 3.5.6.2 below.

16
17 TCMS is also not a Resource Support Service but is related to TSS and is being offered under the
18 FPS rate schedule. It is a service for customers with resources that meet eligibility requirements
19 specified in the CHWM contract.

20
21 BPA is also including pricing for RRS for the first time. RRS is a service that BPA may make
22 available at its discretion to Load Following customers where BPA remarkets non-Federal
23 resources on behalf of customers and provides them with a remarketing credit net of possible
24 remarketing fees for doing so. Further details on RRS are provided in section 3.5.6.3 below.

1 The FPS rate schedule includes a section on the general rate application of the FORS-related,
2 TSS-related, and RRS-related charges and credits. The GRSPs include the formulas for
3 calculating the FORS Capacity and Energy Charges, TSS and TCMS Charges, and RRS Credit
4 for the resources to which FORS, TSS/TMCS, or RRS is applied.

6 **3.5.6.1 Forced Outage Reserve Service**

7 FORS is an optional service for BPA to provide an agreed-upon amount of capacity and energy
8 to a customer with a qualifying resource that experiences a forced outage. This service can be
9 considered to be an insurance product in the event of an unforeseen outage at a generating
10 resource. If a Load Following customer does not choose to take this service, it must supply
11 replacement power if its resource experiences a forced outage. Unless stated otherwise, the
12 resource amounts used in these calculations are those specified in the customer's CHWM
13 contract Exhibit D (Exhibit D amounts) and are planned generation amounts based on hourly
14 generation from the most-recent historical year.

16 **3.5.6.1.1 FORS Pricing Summary**

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

21 The FORS Charges include the following elements:

- 22 • A FORS Capacity charge based on the PFp Tier 1 Demand rate, the calculated firm
23 capacity of the resource for customers whose resource is also taking DFS, and the
24 forced outage rating for the applicable resource.
- 25 • A FORS Energy charge based on a Mid-C index price under two conditions and the
26 kilowatthours supplied during a forced outage event.

1 **3.5.6.1.2 FORS Capacity Charge**

2 **FORS Capacity Rates.** The rates used to calculate the FORS Capacity charge are based on the
3 PFp Demand rates and are listed in GRSP II.U.3.(a)(1).

4
5 **FORS Capacity Billing Determinant.** For each resource, the Capacity billing determinant is
6 the monthly firm capacity multiplied by the forced outage rating. The firm capacity is calculated
7 by the RSS module of RAM in the manner described for the DFS Capacity billing determinant.
8 See section 3.1.15.2.2. The forced outage rating for a resource taking FORS has the same
9 considerations as described in section 3.1.15.4.1.

10
11 **FORS Capacity Charge.** For each resource, the FORS Capacity charge is the product of
12 multiplying the FORS Capacity rate by the FORS Capacity billing determinant for each month.
13 The sum of the monthly values is divided by 12 to calculate a flat monthly charge. The FORS
14 Capacity charge is specified in section 2.4.5.3 of Exhibit D of the CHWM contract.
15 Documentation Table 3.17 shows the FORS Capacity charges that are calculated for each
16 resource currently requesting FORS. The formula for calculating the FORS Capacity charge for
17 each individual resource to which FORS is applied is shown in GRSP II.U.3.(a)(3).

18
19 **3.5.6.1.3 FORS Energy Charge**

20 The purpose of the Energy charge is to pass through the cost of replacement energy that BPA
21 provides during a customer's forced outage.

22
23 **FORS Energy Rate.** The rate for the energy provided during the first 24 hours of a forced
24 outage will be the average of the hourly Powerdex Mid-C Price or its replacement during the
25 hours of the forced outage. The rate for energy provided after the first 24 hours of a forced
26 outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index
27 or its replacement for the applicable diurnal period the energy is provided. If any of the Mid-C

1 prices specified above is less than zero, the FORS Energy rate calculation will be zero for such
2 negative value.

3
4 **FORS Energy Billing Determinant.** The FORS Energy billing determinant is the total actual
5 replacement energy a resource requires to meet the planned generation amount specified in
6 Exhibit D of the customer's CHWM contract, subject to the FORS energy limits specified
7 therein.

8
9 **FORS Energy Charge.** For each resource, the FORS Energy charge is the product of
10 multiplying the FORS Energy rate by the FORS Energy billing determinant. GRSP II.U.3.(b)
11 shows the formula for calculating the FORS energy charges for the individual resources to which
12 FORS is applied.

14 **3.5.6.2 Transmission Scheduling Service and Transmission Curtailment Management** 15 **Service**

16 TSS is a service provided by Power Services to undertake certain scheduling obligations on
17 behalf of the customer. TCMS is a feature of TSS under which BPA provides either replacement
18 transmission or replacement energy to customers that have qualifying resources that experience
19 transmission events pursuant to the conditions specified in Exhibit F of the CHWM contract.

20
21 If a Load Following customer is served by transfer or is purchasing DFS or SCS services from
22 BPA, it is required to have the TSS provisions added to its CHWM contract. Many customers
23 meeting these criteria do not have a non-Federal resource with an e-Tag that must be scheduled
24 to their load. Only customers that have a non-Federal resource that requires an e-Tag will be
25 charged for TSS services. Pursuant to the Load Following CHWM contract, for a customer that
26 is not required to take TSS given the criteria described above, TSS is an optional service if the
27 customer wishes to have BPA produce the e-Tags for its resource(s). If a Load Following

1 customer with a non-Federal resource is not required by its contract to take this service or elects
2 not to take this service, it is required to supply replacement transmission or power when the
3 resource's transmission path experiences an outage or curtailment. If it is unable to do so, it may
4 face an Unauthorized Increase (UAI) charge.
5

6 **3.5.6.2.1 TSS/TCMS Pricing Summary**

7 The charge for TSS reflects the cost of scheduling a resource to its Point of Delivery (POD).

8 The charge for TCMS reflects the cost of providing either replacement transmission or
9 replacement energy when a transmission event occurs. A unique set of charges will be
10 calculated for each resource to which TSS and TCMS are applied. The TSS and TCMS services
11 are applicable to only certain resources a customer may have, as described in Exhibit F of the
12 Load Following CHWM contract. Certain customers must have the TSS provisions included in
13 their CHWM contracts even though they do not have non-Federal resources scheduled to load.
14 These customers will not have a separate TSS charge on their bill. TSS may apply to a resource
15 and TCMS may not, but TCMS will never apply to a resource to which TSS does not apply.
16

17 The TSS/TCMS charges include the following elements:

- 18 • A monthly TSS charge based on the dedicated resource megawatthour amounts found
19 in Exhibit A of the Load Following CHWM contract for FY 2014 and FY 2015 for
20 Specified and Unspecified Resource amounts for resources requiring an e-Tag.
21 Although the contract states these values in megawatthours, BPA bills on
22 kilowatthours, so the appropriate conversion is made.
- 23 • A TSS rate that is based on the Operations Scheduling costs for the two years of the
24 rate period divided by the total megawatthours BPA has scheduled in the two most
25 recent historical years.

- An after-the-fact TCMS charge based on replacement power or transmission costs caused by a transmission event.

3.5.6.2.2 TSS Charge

TSS Rate. The RSS module of RAM calculates a TSS rate that is applied to the billing determinant described below. The rate is calculated by dividing the forecast operations scheduling cost for the rate period (including costs associated with power scheduling preschedule, real-time, and after-the-fact functions) by the total megawatthours of power BPA scheduled in FY 2011 and FY 2012. See Documentation Table 3.7.

TSS Billing Determinant. The TSS billing determinant is the total kilowatthours of planned generation the customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM contract.

TSS Charge. For each resource, the TSS Charge is the product of multiplying the TSS rate by the TSS billing determinant for each month of the rate period (or an individual fiscal year if this service applies in only one fiscal year). The sum of the monthly values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge.

The TSS Charge is subject to a cap such that if the annual cost to the customer using the TSS rate exceeds \$990/month, then the monthly charge is capped at \$990/month. The cap is schedule transaction-based. It is the result of multiplying 30 (the average number of schedules in a month, *i.e.*, one per day) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2011 and FY 2012.

1 In the applicable fiscal year BPA will directly assign to applicable TSS customers the Open
2 Access Technology International, Inc. (OATI) registration fee BPA forecasts to incur on their
3 behalf. Table 3.19 of the Documentation lists the customers subject to the OATI registration fee.

4
5 Table 3.17 of the Documentation shows the individual TSS charges that are calculated for the
6 individual resources to which only TSS is applied and individual resources to which TSS is
7 applied in addition to other RSS products. GRSP II.U.4.(a)(3) shows the formula for calculating
8 the TSS charge for the individual resources to which TSS is applied.

9 10 **3.5.6.2.3 TCMS Charge**

11 A TCMS rate is applied to recover replacement power or transmission costs based on actual
12 transmission events that occur on the planned delivery path between a customer's resource and
13 its load. These transmission events and resource eligibility requirements are defined by terms
14 specified in Exhibit F of the customer's CHWM contract.

15
16 **TCMS Charge if Replacement Power is Provided.** The TCMS rate will be the Powerdex
17 Mid-C hourly index price or its replacement for each hour the transmission event occurs. If a
18 Mid-C price is less than zero, the TCMS energy rate for that hour will be zero. The TCMS
19 billing determinant is the total actual kilowatthours in each hour of replacement power BPA
20 supplies. For each eligible resource, the TCMS Charge is the product of multiplying the TCMS
21 rate by the TCMS billing determinant for each hour of the month.

22
23 **TCMS Charge if Alternative Transmission is Provided.** If Point-to-Point transmission is used
24 for the alternate transmission path used to deliver the customer's eligible resource, for each
25 resource the TCMS Charge is the cost of the additional Point-to-Point transmission purchases

1 plus any additional costs, including real power losses, associated with using the replacement
2 transmission.

3
4 GRSP II.U.4.(b)(3) shows the formula for calculating the TCMS charges for the individual
5 resources to which TCMS is applied.

6
7 For the BP-14 rate period, the TCMS Charge does not include a non-firm Network or Point-to-
8 Point Reservation Fee. BPA is reserving the right to include such a fee in future rate periods for
9 customers wheeling their non-Federal resource to their loads on non-firm Network or non-firm
10 Point-to-Point transmission.

11
12 Application of TCMS to the Tier 2 rates is described in section 3.1.9.1.

13 14 **3.5.6.3 Resource Remarketing Service**

15 Exhibit D of the CHWM contract for Load Following customers offers an optional service for
16 customers that have purchased non-Federal resources in anticipation of future need. At the
17 customer's request and with BPA's agreement, BPA will remarket the excess non-Federal
18 resource amounts on the customer's behalf until the customer's need meets or exceeds that
19 non-Federal resource amount. In order to qualify for this service the customer must also request
20 DFS for the non-Federal resource. The DFS charges will be applicable to both the non-Federal
21 resource amounts the customer dedicates to its load and any portion that BPA remarkets on the
22 customer's behalf. BPA has agreed to provide this service to one customer for FY 2014.

23 Documentation Table 3.20 shows the individual RRS credits that are calculated for the individual
24 resources to which RRS is applied.

1 **3.5.6.3.1 RRS Credit**

2 **RRS Rate.** For each non-Federal resource, the rate will be the flat annual equivalent of the
3 PF Load Shaping rates.

4
5 **RRS Billing Determinant.** The RRS billing determinant will be the annual average megawatt
6 Resource Remarketed Amounts in the customer’s CHWM contract Exhibit D (when updated).

7
8 **RRS Credit.** For each resource, the RRS Credit will be the product of multiplying the RRS rate
9 by the RRS billing determinant for each applicable year of the rate period. The annual value is
10 divided by 12 to calculate a flat monthly credit.

11
12 **RRS Fee.** The fee for providing RRS to Customers is determined on a case-by-case basis.

13
14 **3.5.6.4 TSS Charge Application to Tier 1 Augmentation**

15 TRM section 8 states that RSS pricing will be used to make Federal resource acquisitions
16 financially equivalent to a flat block. In addition, Tier 1 Augmentation is assumed for
17 ratemaking purposes to be in the shape of an annual flat block purchase. TRM section 3.5.
18 The one resource whose costs are allocated to Tier 1 Augmentation is Klondike III, a scheduled
19 resource that requires an e-Tag. The RAM RSS module calculates a TSS charge for this
20 resource. The TSS charge is added to the RSS charges for each year of the rate period that are
21 allocated to the Composite cost pool under the “Non-Slice Augmentation RSC Revenue
22 Debit/(Credit)” line item.

23
24 **3.5.6.5 Credits to the PFp Tier 1 Customer Rate Cost Pools**

25 Forecast revenue credits are calculated from the RSS charges. All revenues, except those from
26 the Resource Shaping Charge, are allocated as credits to the Composite Customer cost pool. The
27 forecast revenue from the Resource Shaping Charge is allocated as a credit to the Non-Slice

1 Customer cost pool. Additional information on these revenue credits is found in sections 3.1.2.1
2 and 3.1.2.2.

3.5.7 Unanticipated Load Service (ULS)

3
4
5 Under the FPS-14 rate schedule, the Resource Replacement (RR) rate will be applied to
6 Unanticipated Load Service for circumstances that cause an increase in a customer's load placed
7 on BPA and not anticipated in the rate case. Such circumstances could include, but are not
8 limited to, delays in the online date of a customer's specified resource for Above-RHWM
9 service; New Specified Resources that are 10 aMW or less and either experience permanent
10 failure during the rate period or fail to come online; and Transfer customers that both (1) cannot
11 secure Firm Network Transmission (NT) from source to sink for their Dedicated Non-Federal
12 resource to their Above-RHWM load by the time power deliveries are to begin under the
13 Regional Dialogue contract, and (2) are expected to face high TCMS charges due to their
14 reliance on Secondary Network Transmission while they pursue Firm Network Transmission.
15 The provision of ULS will be at BPA's sole discretion.

16
17 The energy rate for the RR rate is equal to the Load Shaping rate or the projected market price
18 calculated when a request for ULS is made, whichever is greater. See section 3.1.6.2 for a
19 description of the Load Shaping rate. The ULS Demand rate is equal to the PFp Demand rate,
20 described in section 3.1.6.3. The ULS under the FPS-14 rate schedule is specified in
21 GRSP II.Z.4.

3.6 General Transfer Agreement Service Rate Design

22
23
24 Transfer Services are the transmission and distribution services BPA acquires from other
25 transmission providers to transmit Federal power to BPA customers located within third-party-
26 owned transmission systems. Transfer Service customers may be subject to one or two separate

1 charges from BPA under the General Transfer Agreement Service (GTA-14) rate: (1) the
2 General Transfer Agreement (GTA) Delivery Charge, and (2) the Transfer Service Operating
3 Reserve Charge. In addition to these charges, Transfer Service customers are responsible for the
4 cost of any distribution upgrades associated with their respective points of delivery, as provided
5 in the Supplemental Direct Assignment Guidelines (GRSP I.E.).
6

7 **3.6.1 GTA Delivery Charge**

8 The GTA Delivery Charge, section I of the GTA-14 rate schedule, is a charge for low-voltage
9 delivery service of Federal power provided under GTAs and other non-Federal transmission
10 service agreements over a third-party transmission system. The GTA Delivery Charge applies to
11 power customers that take delivery at voltages below 34.5 kV unless such costs have been
12 directly assigned to the specific customer.
13

14 Since 2002, the GTA Delivery Charge has mirrored the Transmission Services Utility Delivery
15 Charge. For the FY 2014–2015 rate period, the GTA-14 Delivery Charge is calculated as a
16 separate, stand-alone rate. As described in the following section, the rate is \$0.820 per kilowatt
17 per month. The billing determinant for the GTA-14 Delivery Charge also changes, to the
18 customer system peak, which is the same billing determinant Power Services uses to calculate
19 the customer’s power bill.
20

21 **3.6.1.1 GTA-14 Delivery Charge Revenue Requirement**

22 The revenue requirement for the GTA-14 Delivery Charge is computed using FY 2011
23 transmission provider invoices for low-voltage distribution and delivery charges and contract
24 exhibits. The one exception is NorthWestern Energy (NorthWestern), which does not charge
25 separately for low-voltage delivery. To estimate a cost for NorthWestern, the average cost of all
26 other transmission providers is applied to the loads delivered to Power Services’ low-voltage

1 customers served on NorthWestern’s system. FY 2011 numbers are adjusted by applying an
2 annual 0.97 percent escalation (for load growth) through FY 2014 and FY 2015. The average of
3 the FY 2014 and FY 2015 numbers serves as the numerator in the GTA-14 Delivery Charge rate
4 calculation.

5
6 **3.6.1.2 GTA-14 Delivery Charge Billing Determinant**

7 The FY 2011 Customer System Peak is determined by reviewing customer bills and extracting
8 customer load data for the low-voltage PODs at customer system peak. The values are escalated
9 annually by 0.97 percent (for load growth) through FY 2014 and FY 2015. The average of the
10 FY 2014 and FY 2015 numbers serves as the denominator in the GTA-14 Delivery Charge rate
11 calculation.

12
13 The FY 2014–2015 average revenue requirement is divided by the FY 2014–2015 average
14 customer system peak to calculate the rate, as shown below:

| | | |
|----|--|-------------|
| 15 | Distribution and Low-Voltage Costs Average FY 2014–2015: | \$2,059,505 |
| 16 | BPA Customer System Peak Average FY 2014–2015: | \$2,510,867 |
| 17 | GTA-14 Rate FY 2014–2015: | \$0.820 |

18
19 **3.6.2 Transfer Service Operating Reserve Charge**

20 The Transfer Service Operating Reserve Charge is designed to address a potential change in
21 Operating Reserve obligations. Currently, Power Services does not acquire Operating Reserves
22 for delivery of Federal power to customers served by transfer. See Schedule 5 and 6 of the Open
23 Access Transmission Tariff (OATT). Transfer Service customers already pay for these
24 deliveries under the terms of their Network Transmission agreements with Transmission
25 Services. This arrangement reflects the existing reliability requirement that Operating Reserves

1 need be carried only by the balancing authority area in which the transmission customer's
2 resources operate.

3
4 The Western Electricity Coordinating Council (WECC) is proposing that the Commission
5 change this requirement. If proposed operational change BAL-002-WECC-1 is approved by the
6 Commission, a portion of the Operating Reserve obligation for the BPA balancing authority area
7 associated with Transfer Service customers would shift to the balancing authority areas where
8 the Transfer Service customers' loads are located. This proposed change is known as the
9 "3 and 3" reliability standard. This change, if adopted, would shift a portion of the costs for
10 Operating Reserves from Transfer Service customers to BPA.

11
12 In anticipation of this potential change, the Transfer Service Operating Reserve Charge for the
13 FY 2014–2015 rate period is designed to mitigate the cost shift described above in the event the
14 Commission adopts WECC's proposed change. The Transfer Service Operating Reserve Charge
15 rate, if assessed, would be the same as the ACS-14 rate for Operating Reserves that Transmission
16 Services charges to customers that have load in the BPA balancing authority area.

17
18 Due to the uncertainty regarding whether and when WECC's proposed changes may be adopted
19 by the Commission and implemented by the various transmission providers, the implementation
20 of the Transfer Service Operating Reserve Charge has been conditioned upon the satisfaction of
21 three criteria: (1) BPA serves the power customer by Transfer Service; (2) the Transfer Service
22 customer does not pay Transmission Services for Operating Reserves based on the "3 and 3"
23 reliability standard for the customer's load; and (3) BPA is assessed Operating Reserve charges
24 from a third-party transmission provider to transfer Federal power to the power customer's load.
25 BPA will assess the Transfer Service Operating Reserve Charge only if all three criteria have
26 been satisfied.

1 The forecast revenue associated with the Transfer Service Operating Reserve Charge is zero,
2 because implementation of the Transfer Service Operating Reserve Charge will generally result
3 in no net revenue impact. It is anticipated that the increased revenue from Transfer Service
4 customers will be offset by the increased ancillary service costs Power Services will pay to
5 third-party transmission systems.

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4. REVENUE FORECAST

The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2014–2015, and the current year, FY 2013. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect (BP-12 rates), and the second uses proposed rates (BP-14 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-14-FS-BPA-02, sections 3.2 and 3.3. Both forecasts are based on the Power Loads and Resources Study, BP-14-FS-BPA-03, forecast of firm loads for the current fiscal year and the rate period. Because the same load forecast is used for both revenue forecasts, the only revenues that change between current and proposed rates are Priority Firm Power (PF), Industrial Firm Power (IP), and generation inputs revenues. All other revenues remain constant between the two forecasts.

In addition to forecasts of revenues, this chapter 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 2013–2015 and discussed in section 4.5.

The revenue forecast includes revenue calculations for the current year, FY 2013, to estimate the amount of financial reserves available to BPA at the beginning of the rate period. See Power Revenue Requirement Study section 1.1.

The revenue forecast is divided into four main categories: (1) revenues from gross sales, described in section 4.1; (2) miscellaneous revenues, described in section 4.2; (3) revenues from

1 generation inputs for ancillary, control area, and other services, described in section 4.3; and
2 (4) Treasury credits, described in section 4.4.

3 4 **4.1 Revenue Forecast for Gross Sales**

5 Gross Sales is the largest category of revenue for Power Services. There are eight sources of
6 revenue in this category: firm power sales under the CHWM contracts, described in
7 section 4.1.1; Industrial Firm Power sales to DSIs, described in section 4.1.2; pre-Subscription
8 contract sales, described in section 4.1.3; short-term market sales, described in section 4.1.4;
9 long-term contractual obligations, described in section 4.1.5; Canadian entitlement returns,
10 described in section 4.1.6; Renewable Energy Certificates, described in section 4.1.7; and other
11 sales, described in section 4.1.8.

12 13 **4.1.1 Firm Power Sales under CHWM Contracts**

14 For FY 2013, the revenues from Priority Firm Power sales pursuant to CHWM contracts are
15 calculated using the product of (1) forecast loads documented in Power Loads and Resource
16 Study section 2.2 and accompanying Documentation Table 1.2.1 for energy, Table 1.2.2 for
17 HLH, and Table 1.2.3 for LLH; and (2) BP-12 power rates found in the 2012 Wholesale Power
18 Rate Schedules, Section PF-12. Revenues from PF sales pursuant to CHWM contracts for
19 FY 2013 are listed in PRS Table 3, lines 3–12, and in Documentation Table 4.1, lines 3–12.

20
21 For FY 2014–2015, revenues from PF sales pursuant to CHWM Contracts are computed using
22 the product of (1) forecast loads assuming normal weather, documented in the Power Loads and
23 Resources Study and accompanying Documentation; and (2) the appropriate PF rates derived by
24 RAM2014. Inputs and results for the revenue forecast are managed and calculated pursuant to
25 the CHWM contracts using the Revenue Forecasting Application (RFA). Revenues are reported
26 for Tier 1 Customer charges (Composite, Slice, and Non-Slice), Load Shaping, and Demand,

1 including the Low Density Discount and Irrigation Rate Discount credits, and any additional
2 Tier 2 or RSS charges.

3 4 **4.1.1.1 Composite and Non-Slice Customer Charges**

5 Revenues from each customer for the Composite and Non-Slice Customer charges are based on
6 the customer's TOCA and the customer's contractually specified products. There are no Slice
7 charges for FY 2014–2015. Revenues obtained from the Composite and Non-Slice Customer
8 charges represent the majority of revenues from firm power sales under CHWM contracts for
9 FY 2014–2015. An example calculation of the Composite and Non-Slice charges is available in
10 Documentation Table 4.3. Composite and Non-Slice revenues for FY 2014–2015 are listed in
11 Table 4, lines 3–4, and Documentation Table 4.2, lines 3–4.

12 13 **4.1.1.2 Load Shaping Charge**

14 The Load Shaping charge reflects the costs and benefits of shaping the Tier 1 System Capability
15 to the monthly and diurnal shape of a customer's below-RHWM load. A charge to the customer
16 results when the customer's shaped load is greater than its share of the Tier 1 System Output in
17 any month for both HLH and LLH; the customer will receive a credit from BPA when the
18 opposite occurs. The Load Shaping charge is described in section 3.1.6.2, and an example
19 calculation of the Load Shaping charge is available in Documentation Table 4.4. Load Shaping
20 revenues for FY 2014–2015 are listed in Table 4, line 6, and Documentation Table 4.2, line 6.

21 22 **4.1.1.3 Demand Charge**

23 The Demand charge is applicable to customers purchasing Load Following or Block with
24 Shaping Capacity products; for FY 2014–2015, there are no customers purchasing Block with
25 Shaping Capacity. The Demand charge is calculated using customer-specific information
26 including actual Customer Tier 1 System Peak, average actual monthly below-HWM load

1 occurring in HLH, CDQs, and Super Peak Credit (if applicable). Calculation of a customer's
2 Demand charge is described in section 3.1.6.3, and an example calculation is available in
3 Documentation Table 4.4. Demand revenues for FY 2014–2015 are listed in Table 4, line 7, and
4 Documentation Table 4.2, line 7.

6 **4.1.1.4 Irrigation Rate Discount (IRD)**

7 The IRD is a rate credit available to eligible customers and provides a fixed rate discount on
8 Tier 1 rates (the discount does not apply to loads served at Tier 2 rates). May through September
9 eligible irrigation loads are identified in each customer's CHWM contract. The methodology for
10 calculating the IRD end-of-year true-up appears in GRSP II.K.3. Forecast credits for irrigation
11 loads are calculated using an IRD that is derived by multiplying the irrigation loads identified in
12 the CHWM contracts by the IRD rate. The IRD is described in section 3.1.11, and an example
13 calculation is available in Documentation Table 4.5. IRD credits for FY 2014–2015 are listed in
14 Table 4, line 8, and Documentation Table 4.2, line 8.

16 **4.1.1.5 Low Density Discount (LDD)**

17 The LDD is provided for in section 7(d)(1) of the Northwest Power Act and offers a discount to
18 avoid adverse impacts on retail rates of BPA's customers with low system densities. Discounts
19 up to 7 percent are available for customers that meet the criteria specified in GRSP II.M. As set
20 forth in the TRM, LDD percentages are calculated to provide a discount on power purchased at
21 Tier 1 rates that approximates the discount the customer would have received under non-tiered
22 rates. An example calculation is available in Documentation Table 4.6. LDD credits for
23 FY 2014–2015 are listed in Table 4, line 9, and Documentation Table 4.2, line 9.

1 **4.1.1.6 Tier 2 and Resource Support Services (RSS)**

2 Tier 2 rates are based on a cost allocation that recovers the cost of BPA service to Above-
3 RHWL load. Tier 2 revenues are based on sales to customers that have elected to have BPA
4 serve their Above-RHWL load. Revenues for FY 2014–2015 are listed in Table 4, line 10, and
5 Documentation Table 4.2, line 10.

6
7 RSS allows a customer to apply the variable output of a resource to serve its Above-RHWL load
8 without having to guarantee a specific scheduled shape of this resource. These services are
9 available for all specified non-Federal resources that Load Following customers contractually
10 dedicate to serve their total retail load and for specified new renewable resources that
11 Slice/Block customers contractually dedicate to serve their total retail load. Revenues from these
12 services are based on known services chosen by customers. Revenues for FY 2014–2015 are
13 listed in Table 4, line 11, and Documentation Table 4.2, line 11.

14
15 **4.1.2 Sales to Direct Service Industrial Customers**

16 BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the
17 product of (1) forecast loads of 320 aMW for FY 2013 and 312 aMW for FY 2014–2015,
18 documented in Power Loads and Resources Study section 2.3 and accompanying Documentation
19 Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH; and (2) the appropriate
20 IP rate from RAM2014. For FY 2013, the revenues for DSI customers are calculated using the
21 IP-12 rate. Revenues for FY 2013–2015 are listed in PRS Table 4, line 13, and Documentation
22 Table 4.2, line 13.

23
24 **4.1.3 Pre-Subscription Sales**

25 During FY 2013–2015, BPA is providing power to one customer under a pre-Subscription
26 contract. The revenues from the pre-Subscription customer are derived by multiplying the
27 individual customer loads by the appropriate FPS rate, both of which are set pursuant to the

1 pre-Subscription contract. Revenues for FY 2013–2015 are listed in Table 4, line 14, and
2 Documentation Table 4.2, line 14.

3 4 **4.1.4 Short-Term Market Sales**

5 The revenue forecast includes revenues from the sales of surplus energy, which can be a
6 combination of secondary energy, which is energy produced using streamflows in excess of
7 critical (1937) water conditions, and firm energy, which results from firm resources in excess of
8 those required to serve firm loads. For rate development purposes, the forecast of firm FCRPS
9 output is based upon critical (1937) water conditions. See Power Loads and Resources Study
10 section 3.1.2.1.3. FCRPS output, while uncertain, is expected to be greater than under 1937
11 water conditions, and thus secondary energy sales and revenue result. The forecast of surplus
12 energy sales considers varying loads and resources, such that under some conditions, firm energy
13 is available for sale into the wholesale market. The wholesale market price effects of a number
14 of factors are considered in determining the forecast for surplus sales revenue.

15
16 For FY 2013, the surplus energy revenue included in the revenue forecast consists of current-
17 year actuals plus the average of the surplus energy revenues in forecast months computed during
18 RevSim simulations of 40 games for each of 80 historical water years, for a total of 3,200 games.
19 For FY 2014–2015, the surplus energy revenue is the median of the surplus energy revenues
20 across those 3,200 games. This power is assumed sold under the FPS rate schedule.

21
22 The revenue forecast for short-term market sales is computed using RevSim to calculate monthly
23 HLH and LLH energy surpluses for each of the 3,200 games, applying corresponding market
24 prices developed for each game. See Power Risk and Market Price Study, BP-14-FS-BPA-04,
25 section 2.6.3, and Risk Documentation Table 21. Revenues for FY 2013–2015 are shown in
26 PRS Table 4, line 15, and Documentation Table 4.2, line 15.

1 **4.1.5 Long-Term Contractual Obligations**

2 Long-term obligation contracts include the WNP-3 Exchange Settlements, a wind energy
3 exchange, capacity and energy exchanges, and a seasonal power exchange. For FY 2013–2015,
4 revenue from these contractual obligations is calculated pursuant to the individual contracts and
5 then summed and added to the forecast as a group. Note that neither the capacity and energy
6 exchanges nor the seasonal power exchange generate revenue. Revenue for FY 2013–2015 is
7 listed in Table 4, line 16, and Documentation Table 4.2, line 16.

8
9 **4.1.6 Canadian Entitlement Return**

10 The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the
11 border pursuant to Contract No. 99EO-40003. No revenues are generated from the delivery of
12 this power, but energy amounts are listed in the revenue forecast to represent this system
13 obligation. The average megawatt deliveries for FY 2013–2015 are listed in Table 4, line 17,
14 and Documentation Table 4.2, line 17.

15
16 **4.1.7 Renewable Energy Certificates (RECs)**

17 RECs are the environmental attributes corresponding to one megawatthour of generation from a
18 renewable energy resource. BPA sells a portion of the RECs it receives as part of its energy
19 purchases from six wind projects. Under the Subscription contracts, 43 preference customers
20 had rights to purchase RECs through FY 2016, of which about half exercised those rights, for an
21 annual average of 12.5 aMW for FY 2014–2015. The price for the RECs is set outside the rate
22 proceeding pursuant to the terms of the contracts. In May 2011 BPA established the REC prices
23 as \$8.00 for FY 2013, \$10.25 for FY 2014, and \$15.00 for FY 2015. After BPA satisfies these
24 contract obligations, the RECs remaining in BPA’s inventory for FY 2014–2015 will be
25 distributed on a pro-rata basis to all CHWM customers based on customers’ RHWMs. RECs are
26 distributed at no additional charge to the customers and do not generate any revenue for Power

1 Services. Revenues for RECs in FY 2014–2015 are listed in Study Table 4, line 18, and
2 Documentation Table 4.2, line 18.

3 4 **4.1.8 Other Sales**

5 Other sales include forecast revenues from the Slice True-Up and Load Shaping True-Up, which
6 are applicable only for FY 2013. Other sales revenue for FY 2013–2015 is listed in Table 4,
7 line 19, and Documentation Table 4.2, lines 19–22.

8 9 **4.2 Revenue Forecast for Miscellaneous Revenues**

10 Miscellaneous Revenues include revenues from the General Transfer Agreement (GTA) delivery
11 charge, Energy Efficiency, Downstream Benefits, U.S. Bureau of Reclamation (Reclamation)
12 power for irrigation, and the Upper Baker project. The GTA delivery charge is described in
13 section 3.6. Energy Efficiency revenues are received by BPA as reimbursements for costs
14 relating to implementation of various energy efficiency projects. For FY 2013–2015, revenues
15 from Energy Efficiency are calculated by estimating project expenses. While these revenues are
16 wholly offset by the associated expenses, which are recorded on the expense ledger, the expenses
17 are included in the revenue requirement; therefore, the revenues are included in this forecast.

18
19 Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated
20 planning and operation of U.S. Army Corps of Engineers (Corps) and Reclamation upstream
21 storage reservoirs as part of the Pacific Northwest Coordination Agreement. For FY 2013–2015,
22 revenues from Downstream Benefits are calculated by applying a forecast of the operations and
23 maintenance costs adjusted for inflation to the energy amounts from the most recent study
24 conducted by the Northwest Power Pool (NWPP). The NWPP conducts a study each year on
25 behalf of the utilities to calculate the energy amounts used in determining the Downstream
26 Benefits.

1 Reclamation power for irrigation includes power that has been reserved from the FCRPS for use
2 at Reclamation projects. For revenue forecasting purposes, power that has been reserved for
3 Reclamation irrigation projects is classified as either “Reserved Power” or “Irrigation Pumping
4 Power.” Revenue from Reserved Power for FY 2013, 2014, and 2015 is forecast in equal
5 monthly amounts based on an annual amount that is aggregated for Reclamation projects. The
6 annual aggregated amounts are forecast based on historical information provided by
7 Reclamation. Revenue from Irrigation Pumping Power for FY 2013, 2014, and 2015 is
8 calculated using the forecast irrigation pumping load times the price set in individual contracts.

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

17
18 Miscellaneous revenues for FY 2013–2015 are listed in Table 4, line 21, and Documentation
19 Table 4.2, lines 24–30.

21 **4.3 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 inputs for
24 ancillary and control area services. This revenue forecast includes generation inputs for
25 Regulating Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve,
26 Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Operating Reserves.
27 Power Services receives revenue from Transmission Services for providing generation inputs for

1 other services, including Synchronous Condensing, Generation Dropping, Energy Imbalance,
2 and Generation Imbalance. Other inter-business line allocations revenues include Redispatch,
3 Segmentation of Corps and Reclamation network and delivery facilities costs, and station
4 service. Information related to generation inputs is presented in the Generation Inputs Study,
5 BP-14-FS-BPA-05. Revenues are listed in Study Table 4, line 22, and Documentation Table 4.2,
6 lines 31–54.

8 **4.4 Revenue from Treasury Credits**

9 Revenues are also forecast from two kinds of Treasury credits, or deductions made from BPA’s
10 annual Treasury payment. These credits represent a partial reimbursement by the Treasury for
11 expenses incurred by BPA throughout the year.

13 **4.4.1 Section 4(h)(10)(C) Credits**

14 Section 4(h)(10)(C) of the Northwest Power Act states that the amounts BPA spends for
15 protecting, enhancing, and mitigating fish and wildlife in the region shall be allocated among the
16 FCRPS hydro projects based on the various project purposes. BPA pays the entirety of the costs
17 relating to the obligations of section 4(h)(10)(C) and is reimbursed by the U.S. Treasury for
18 22.3 percent of the replacement power purchases BPA is expected to make due to fish
19 mitigation, as well as an equal percentage of program and capital expenses related to the fish and
20 wildlife programs. The 22.3 percent represents the non-power portion of the total FCRPS costs,
21 which is the responsibility of taxpayers rather than BPA ratepayers. This credit is treated as
22 Power Services revenue.

23
24 Program and capital expenses relating to fish and wildlife programs are discussed in the Power
25 Revenue Requirement Study. The methodology for estimating the replacement power purchases
26 resulting from changes in hydro system operations to benefit fish and wildlife is described in

1 Power Loads and Resources Study section 3.3.1. The cost of the increased purchases is
2 estimated using RevSim and the market price forecast and is included in Power Risk and Market
3 Price Study section 2.6.1 and Risk Documentation Table 16. Revenue from 4(h)(10)(C) credits
4 is listed in PRS Table 4, line 23, and Documentation Table 4.2, line 55.

6 **4.4.2 Colville Settlement Credits**

7 The Colville Settlement Act Credits are discussed in section 1.2.3 of the Power Revenue
8 Requirement Study. The Colville Settlement Agreement obligates BPA to make annual
9 payments to the Colville Tribes. BPA receives annual credits from the U.S. Treasury against
10 payments due the U.S. Treasury to defray a portion of the costs of making payments to the
11 Colville Tribes. The Treasury credit for the Colville Settlement in FY 2014 and FY 2015 is set
12 by legislation at \$4.6 million per year. Public Law No. 103-436; 108 Stat. 4577, as amended.
13 The credit is listed in PRS Table 4, line 24, and Documentation Table 4.2, line 56.

15 **4.5 Power Purchase Expense Forecast**

16 Power Services forecasts three types of power purchase expenses: Augmentation Purchases,
17 Balancing Purchases, and Other Power Purchases. Although most expenses, including some
18 power purchase expenses, such as long-term generating resources, are forecast in the Power
19 Revenue Requirement Study, the power purchase expenses described here are directly related to
20 load, resource, and price assumptions used to develop power rates. Therefore, they are included
21 in the Power Services revenue forecast.

23 **4.5.1 Augmentation Purchase Expense**

24 For planning purposes, the forecast of firm FCRPS output is based upon critical (1937) water
25 conditions. See Power Loads and Resources Study section 3.1.2.1.3. The forecast annual firm
26 FCRPS output under critical water plus the output of other Federal resources may not be

1 adequate to meet annual average firm loads. Therefore, system augmentation is added to Federal
2 resources to balance firm annual resources with firm annual loads. The Power Loads and
3 Resources Study projects the need to acquire system augmentation of 21 aMW in FY 2014 and
4 318 aMW in FY 2015 to meet firm loads. Augmentation is documented in Power Load and
5 Resources Study section 4.2.

6
7 The forecast expense for the augmentation is based on projected prices using the AURORAxmp
8 model assuming critical water conditions. See Power Risk and Market Price Study
9 Documentation Table 16. Augmentation purchase amounts for FY 2013–2015 are listed in PRS
10 Table 4, line 26, and Documentation Table 4.2, line 58.

11 12 **4.5.2 Balancing Power Purchases**

13 Balancing power purchases are calculated by RevSim, which finds any monthly HLH and LLH
14 energy deficits by simulations of 40 games in each of the 80 water years, for a total of
15 3,200 games, and applying the corresponding market prices developed for each game. Similar to
16 the treatment of short-term market sales, the median value for balancing purchases over the
17 3,200 games is reported for FY 2013 for forecast months and added to actual purchases in past
18 months, and the median value is reported for FY 2014–2015. Total balancing purchase expense
19 for FY 2013–2015 is listed in PRS Table 4, line 27, and Documentation Table 4.2, line 59. A
20 full description is available in Power Risk and Market Price Study section 2.6.3 and Power Risk
21 and Market Price Study Documentation Table 22.

22 23 **4.5.3 Other Power Purchases**

24 The majority of other power purchases are committed winter hedging purchases BPA has made
25 to cover forecast HLH energy deficits during winter months. In those months and water years in
26 which firm loads exceed resources, winter hedging purchases reduce balancing purchases.

1 Conversely, in those months and water years where resources are sufficient to serve firm loads,
2 winter hedging purchases increase the amount of surplus sales. RevSim accounts for the energy
3 relating to winter hedging purchases in the balancing purchases category. However, the amount
4 of expense is included separately.

5
6 The cost of Tier 2 power is also included in other power purchases, as are other miscellaneous
7 contracts. Total other power purchase expense for FY 2013–2015 is listed in Table 4, line 28,
8 and Documentation Table 4.2, line 60.

9 10 **4.6 Summary Table of Power Revenues**

11 A detailed table of power revenues is available in Study Tables 3 and 4 and in Documentation
12 Tables 4.1 and 4.2.

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1 **5. RATE SCHEDULES**

2 The power rate schedules establish the applicability of each rate schedule to products that BPA
3 offers, the rates for the products, the billing determinants to which the rates are applied, and
4 references to sections of the General Rate Schedule Provisions (GRSPs) that apply to each rate
5 schedule. The Power rate schedules described in this section are presented in their entirety in
6 BP-14-A-03-AP01.

7
8 **5.1 Priority Firm Power Rate, PF-14**

9 The PF-14 rate schedule is available for the contract purchase of Firm Requirements Power
10 pursuant to section 5(b) of the Northwest Power Act. Utilities participating in the Residential
11 Exchange Program under section 5(c) of the Northwest Power Act may purchase PF Power
12 pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program
13 Settlement Implementation Agreement.

14
15 **5.1.1 Firm Requirements Power under a CHWM Contract**

16 Rates for firm requirements purchases under a CHWM contract include Tier 1 rates, Tier 2 rates,
17 Resource Support Services rates, and the Unanticipated Load rate. The Tier 1 rates are
18 comprised of the three Customer charge rates (Composite, Non-Slice, Slice), Demand rates, and
19 Load Shaping rates. Tier 2 rates include the Short-Term, Load Growth, and Vintage 2014 rates.
20 Resource Support Services rates are provided for Diurnal Flattening Service, Resource Shaping,
21 and Secondary Crediting Service. Unanticipated Load rates are applicable to requests for firm
22 requirements service to unanticipated load.

1 **5.1.2 Firm Requirements Power under a Contract other than a CHWM Contract**

2 Rates for firm requirements purchases under other than a CHWM contract include the PF
3 Melded rate and the Unanticipated Load rate. The PF Melded rate includes energy and demand
4 rates.

5
6 **5.1.3 PF Exchange Rate**

7 The PF Exchange rates apply to sales under a Residential Purchase and Sale Agreement or
8 Residential Exchange Program Settlement Implementation Agreement. A utility-specific
9 PF Exchange rate is calculated for each utility purchasing Residential Exchange Program power.

10
11 **5.2 New Resources Firm Power Rate, NR-14**

12 The NR-14 rate is applicable to sales to investor-owned utilities under Northwest Power Act
13 section 5(b) requirements contracts. The NR-14 rate is also applicable to sales to any public
14 body, cooperative, or Federal agency to the extent such power is used to serve any new large
15 single load, as defined by the Northwest Power Act. The NR-14 rate includes energy, load
16 shaping, and demand rates. The NR-14 rate schedule also includes the Unanticipated Load rate.

17
18 **5.3 Industrial Firm Power Rate, IP-14**

19 The IP-14 rate schedule is available for firm power sales to DSIs, as defined by the Northwest
20 Power Act, pursuant to section 5(d). The IP-14 rate includes energy and demand rates. DSIs
21 purchasing power pursuant to the IP-14 rate schedule are required to provide the Minimum DSI
22 Operating Reserve – Supplemental.

23
24 **5.4 Firm Power Products and Services Rate, FPS-14**

25 The FPS-14 rate schedule is available for the purchase of Firm Power, Capacity Without Energy,
26 Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change

1 Services, Reassignment or Remarketing of Surplus Transmission Capacity, Transmission
2 Scheduling Service/Transmission Curtailment Management Service, Forced Outage Reserve
3 Service, Resource Remarketing Service, and Unanticipated Load Service under the Resource
4 Replacement rate. Rates and billing determinants for the products and services sold under the
5 FPS rate schedule are either specified by BPA or mutually agreed by BPA and the customer.

6
7 **5.5 General Transfer Service Agreement Rate, GTA-14**

8 The GTA-14 rate schedule includes the GTA Delivery Charge and the Transfer Service
9 Operating Reserve Charge applicable to customers served by low-voltage facilities under a
10 general transfer agreement.

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1 **6. GENERAL RATE SCHEDULE PROVISIONS**

2 The GRSPs describe the adjustments, charges, and special rate provisions applicable to the
3 various rate schedules. The GRSPs also define the power products and services BPA offers and
4 define other applicable terms. This section includes brief descriptions of provisions that are not
5 described elsewhere in the Study. The GRSPs described in this section are presented in their
6 entirety in BP-14-A-03-AP01.

7
8 **6.1 Supplemental Direct Assignment Guidelines**

9 The Supplemental Direct Assignment Guidelines address how BPA will recover the costs for
10 facility expansions and upgrades on third-party transmission systems for transfer service
11 customers. The Supplemental Direct Assignment Guidelines, in conjunction with the
12 Transmission Services Guidelines for Direct Assignment Facilities, as described in the
13 Transmission Services Business Practices, are used to determine whether and in what way
14 specific facility or expansion costs should be assigned to particular transfer service customers.
15 See GRSP I.E.

16
17 **6.2 Conservation Surcharge**

18 Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge
19 recommended by the Northwest Power and Conservation Council pursuant to section 4(f)(2) of
20 the Northwest Power Act. BPA does not currently anticipate applying such a surcharge in the
21 FY 2014-2015 rate period. See GRSP II.A.

1 **6.3 Cost Contributions**

2 Section 7(j) of the Northwest Power Act states that BPA’s rate schedules must indicate the
3 approximate cost contribution of different resource categories to BPA’s rates for the sale of
4 energy and capacity. The rate schedule also must indicate the cost of resources BPA acquires to
5 meet load growth and the relation of such cost to BPA’s average resource cost. See GRSP II.B.
6

7 **6.4 Cost Recovery Adjustment Clause (CRAC)**

8 The CRAC is a mechanism that results in an upward rate adjustment to respond to the financial
9 risks BPA faces before BPA can conduct a section 7(i) rate proceeding to adjust its rates. If
10 stated conditions are met, the CRAC will trigger, and a rate increase will go into effect beginning
11 on October 1 of the applicable year. See GRSP II.C and Power Risk and Market Price Study
12 section 3.2.3.
13

14 **6.5 Dividend Distribution Clause (DDC)**

15 The DDC is a mechanism that results in a downward rate adjustment to return accumulated net
16 revenues to customers when BPA’s cash reserves exceed a pre-defined level. If stated conditions
17 are met, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of
18 the applicable year. See GRSP II.E and Power Risk and Market Price Study section 3.2.5.
19

20 **6.6 DSI Reserves Adjustment**

21 In the event that BPA agrees to acquire an additional reserve product from a DSI, this adjustment
22 (1) establishes the mechanism through which BPA compensates the DSI; and (2) places a cap on
23 the unit price of any reserve product to be purchased to ensure that the reserve acquisition is cost
24 effective. See GRSP II.F.
25
26

1 **6.7 Flexible New Resource Firm Power Rate Option**

2 The Flexible NR rate option, offered at BPA’s discretion, allows NR-14 rates and billing
3 determinants to be modified to accommodate a customer’s request to change the way power is
4 charged under the NR-14 rate schedule. The GRSP describes the factors that will be considered
5 in such modifications. See GRSP II.H.

6
7 **6.8 Flexible Priority Firm Power Rate Option**

8 The Flexible PF rate option, offered at BPA’s discretion, allows PF-14 rates and billing
9 determinants to be modified to accommodate a customer’s request to change the way power is
10 charged under the PF-14 rate schedule. The GRSP describes the factors that will be considered
11 in such modifications. See GRSP II.I.

12
13 **6.9 The NFB Mechanisms**

14 There are two NFB mechanisms, which allow BPA to recover additional revenue if financial
15 impacts from a specified set of circumstances in the fish and wildlife arena cause a reduction in
16 Power Services’ forecast net revenue. The first mechanism, the NFB Adjustment, could result in
17 an increase in the maximum revenue recoverable under a CRAC. The second mechanism, the
18 Emergency NFB Surcharge, could result in a rate increase within the fiscal year. See GRSP II.N
19 and Power Risk and Market Price Study section 4.2.

20
21 **6.10 Priority Firm Power (PF) Shaping Option**

22 If requested, BPA will, to the maximum extent practicable while ensuring timely BPA cost
23 recovery, accommodate individual customer requests to reshape charges within each year of the
24 rate period to mitigate adverse cash flow effects on the customer. Such reshaping of charges
25 must recover the same number of dollars on a net present value basis within the fiscal year as

1 would have been recovered without the reshaping. The reshaping of the payments will be agreed
2 upon between BPA and the customer prior to the start of the rate period. See GRSP II.P.

3 4 **6.11 Remarketing**

5 Remarketing is a credit that conveys the value of BPA's remarketing committed Tier 2 purchases
6 in excess of need and non-Federal resources to which DFS applies that are temporarily in excess
7 of need. The excess is created when commitments to purchase are made prior to establishing
8 need in the RHW process. See GRSP II.R.

9 10 **6.12 REP 7(b)(3) Surcharge Adjustment**

11 The Residential Exchange Program 7(b)(3) surcharge is a utility-specific addition to one of the
12 Base PF Exchange rates that recovers each REP participant's allocated share of rate protection
13 provided pursuant to section 7(b)(2) of the Northwest Power Act. Each REP participant's initial
14 7(b)(3) surcharge is determined in a section 7(i) rate proceeding based on a Base PF Exchange
15 rate and the Average System Cost (ASC) and forecast exchange loads of all utilities assumed for
16 ratemaking to participate in the Residential Exchange Program. Each REP participant's initial
17 7(b)(3) surcharge is displayed in section 6.1 of the PF-14 rate schedule. Each 7(b)(3) surcharge
18 is subject to change during the rate period if any participant's ASC changes during the rate
19 period due to the addition or removal of a resource from the participant's resource portfolio or
20 the planned addition of a new large single load in the service territory of the participant. The
21 procedures for modifying the 7(b)(3) surcharges of all REP participants are codified in
22 GRSP II.T.

23 24 **6.13 TOCA Adjustment**

25 For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA for
26 each year of the rate period is calculated in the BP-14 7(i) process. A customer's TOCA for a

1 fiscal year may be adjusted to account for a significant change in the customer's total load, as
2 detailed in GRSP II.Y, for a mid-year change to a customer's annual net requirement, or for a
3 change in a customer's Provisional CHWM.
4

5 **6.14 Unanticipated Load Service**

6 Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received
7 after February 1, 2013, that results in an unanticipated increase in a customer's load placed on
8 BPA during the FY 2014-2015 rate period. Contractual obligations that result from a request for
9 service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also
10 may apply to a customer that adds load through retail access, including load that was once served
11 by the customer and returns under retail access. See GRSP II.Z.
12

13 **6.15 Unauthorized Increase Charges**

14 The Unauthorized Increase (UAI) charge is a penalty charge to customers taking more power
15 from BPA than they are contractually entitled to take. The UAI demand charge is 1.25 times the
16 applicable monthly demand rate. The UAI energy charge is the greater of 150 mills/kWh or
17 2.0 times the highest hourly Powerdex Mid-C Index price for firm power for the month. See
18 GRSP II.AA.
19
20
21
22
23
24
25
26

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1 **7. SLICE TRUE-UP**

2 **7.1 Slice True-Up Adjustment**

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

7
8 **7.2 Composite Cost Pool True-Up**

9 The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for
10 the Composite cost pool for each fiscal year. For each Slice customer, the annual Slice True-Up
11 Adjustment Charge for the Composite cost pool will be calculated as shown in GRSP II.W.1.
12 The dollar amount calculated may be positive or negative. The Composite Cost Pool True-Up
13 Table (GRSP Table G) shows the forecast expenses, revenue credits, and adjustments that form
14 the basis for the Slice True-Up Adjustment calculation for the Composite cost pool for the
15 applicable fiscal year.

16
17 The following sections discuss the treatment of certain expenses, revenue credits, and
18 adjustments included in the Composite Cost Pool True-Up.

19
20 **7.2.1 System Augmentation Expenses**

21 System augmentation expenses are included in the FY 2014-2015 Composite cost pool. Part of
22 these augmentation expenses is a cost for service to non-Slice customers’ Above-RHWM load
23 that is served at Load Shaping rates. For a description of these system augmentation expenses,
24 see section 3.1.3.3.

1 System augmentation expenses are not subject to the Composite Cost Pool True-Up. However,
2 implicit in the Composite Cost Pool True-Up of the firm surplus and secondary adjustment for
3 Unused RHW and the DSI revenue credit are adjustments that reflect the effects of additional
4 power purchases (or lack thereof) or additional power sales to the market. See sections 3.1.3.2,
5 7.2.3, and 7.2.4 for descriptions of the treatment of the firm surplus and secondary adjustment for
6 unused RHW and the DSI revenue credit for Composite Cost Pool True-Up purposes.

7
8 BPA's purchase of output from the Klondike III resource is a Tier 1 augmentation expense, and
9 the Composite cost pool includes the cost of Resource Support Services and Resource Shaping
10 Charges to shape the generation output of Klondike III into a flat annual block of power.
11 Because the RSS and RSC charges financially convert the variable output of Klondike III to a
12 firm annual block of power, the augmentation expense and RSS and RSC costs associated with
13 generation output from the Klondike III resource are not subject to the Composite Cost Pool
14 True-Up.

16 **7.2.2 Balancing Augmentation Load Adjustment**

17 The Balancing Augmentation Load Adjustment can result in a positive or negative credit to the
18 Composite cost pool. See section 3.1.3.3 for a description of the Balancing Augmentation Load
19 Adjustment, the circumstances that would result in a credit, and the circumstances that would
20 result in a negative credit. The Balancing Augmentation Load Adjustment is not subject to the
21 Composite Cost Pool True-Up.

23 **7.2.3 Firm Surplus and Secondary Adjustment from Unused RHW**

24 The Firm Surplus and Secondary Adjustment from Unused RHW is subject to the Composite
25 Cost Pool True-Up. See GRSP II.W.1.(a). The adjustment reflects the fact that when the sum of
26 actual TOCAs is greater than the sum of forecast TOCAs, additional power is sold to customers

1 at the Composite Customer rate, and it is assumed that additional costs are incurred in the form
2 of forgone market sales or increased power purchases. Likewise, when the sum of actual
3 TOCAs is less than the sum of forecast TOCAs, less power is sold to customers at the Composite
4 Customer rate, and it is assumed that more power is sold in the market or fewer power purchase
5 costs are incurred.

7 **7.2.4 DSI Revenue Credit**

8 The forecast costs associated with service to the DSIs are included in the Composite cost pool.
9 See TRM section 3.2.1.3. DSI revenues received by BPA are included in the Composite cost
10 pool as credits. The DSI Revenue Credit is subject to the Composite Cost Pool True-Up. See
11 GRSP II.W.1.(b).

12
13 The calculation of the DSI revenue credit starts with the forecast DSI revenue credit, which then
14 is adjusted to calculate the actual DSI revenue credit. When the actual DSI sales are greater than
15 the rate case forecast DSI sales, it is assumed that additional power is sold to the DSIs at the
16 IP rate, and additional costs are incurred in the form of forgone market sales or increased power
17 purchases. The adjustment to the forecast DSI revenue credit reflects the revenues from the
18 additional power sold to the DSIs and the additional costs that are incurred. Likewise, when the
19 actual DSI sales are less than the rate case forecast DSI sales, it is assumed that less power is
20 sold to DSIs at the IP rate and more power is sold in the market, or it is assumed that such power
21 may be used to meet BPA obligations so that fewer power purchase costs are incurred. The
22 adjustment to the forecast DSI revenue credit will reflect these effects. The adjustment will also
23 include any DSI take-or-pay revenues recorded by BPA, if applicable.

1 **7.2.5 Unspent Green Energy Premium Revenues**

2 There is unspent GEP revenue that is forecast to remain at the end of FY 2013, and thus a contra-
3 expense is included in the Composite Cost Pool True-Up. The forecast amount of contra-
4 expense for the BP-14 rate period is \$1.5 million. See GRSP Table G.

5
6 **7.2.6 Interest Earned on the Bonneville Fund**

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

14
15 BPA has made several adjustments to the base reserve amount in setting the BP-14 rates, as
16 shown on PRS Table 5. The adjustments reflected in Table 5 are not amounts that have been
17 shared with or collected from Slice customers through a prior Slice True-Up. As a result, these
18 amounts are reflected as adjustments to the size of the base amount of financial reserves. As
19 shown on Table 5, the revised reserve amount for purposes of calculating the interest credit is
20 \$570.26 million. The forecast interest credit for the Composite cost pool is \$7.93 million in
21 FY 2014 and \$11.92 million in FY 2015.

22
23 The interest credit on the financial reserves amount is subject to the Composite Cost Pool
24 True-Up. The actual interest credit calculated on the revised base amount of financial reserves
25 can change from the forecast interest credit if there are changes in the factors used to calculate

1 the forecast interest credit. See Revenue Requirement Study Documentation, BP-14-FS-
2 BPA-02A, section 5, for a description of how the interest credit calculation factors can change.

4 **7.2.7 Prepay Offset Credit**

5 TRM section 2.7.3, addresses the treatment of new costs or new credits in the Annual Slice
6 True-Up Adjustment. The Prepay Offset Credit is a new credit and represents the interest income
7 earned on the power prepayment funds deposited in the Bonneville Fund in FY 2013 and in
8 applicable future fiscal years. The power prepayment funds are being applied toward the capital
9 spending on the Federal hydro maintenance program, the cost of which is included in the
10 Composite cost pool. Because BPA received the proceeds of the prepayment program in
11 advance of their expenditure, interest income will accrue in the Bonneville Fund. The Prepay
12 Offset Credit is included in the calculation of net interest expense in the Composite cost pool
13 table, Table G. See BP-14 Final ROD, BP-14-A-03, section 2.3.3. In the Slice True-Up process,
14 the Prepay Offset Credit will be trued up annually to ensure that the amount of credit reflects the
15 actual amount of interest earned on the prepay funds. See Power Revenue Requirement Study
16 Documentation, BP-14-FS-BPA-02A, section 2, Table 2I, and section 5, Table 5A, for forecast
17 amounts.

19 **7.2.8 Bad Debt Expenses**

20 Bad debt expenses, if any, are allocated between the Composite cost pool and the Non-Slice cost
21 pool, as specified on TRM Table 2A. There is no forecast bad debt expense for the FY 2014-
22 2015 period for ratesetting purposes. If a bad debt expense is identified and accounted for in
23 BPA's actual audited financial reports for a given fiscal year, BPA would determine whether the
24 expense should be included in the actual expenses and revenue credits that are allocable to the
25 Composite cost pool in the applicable fiscal year of the rate period. If so, then the expense may
26 be included for purposes of the Composite Cost Pool True-Up, and the bad debt expense would

1 be allocated according to the principle of cost causation, as described generally in TRM
2 section 2.1.

3
4 Any bad debt expense associated with a sale to any customer that purchased Federal power
5 exclusively at the FPS-12 and FPS-14 rates would be excluded for Composite Cost Pool True-Up
6 purposes. Bad debt expenses associated with sales of power at only these FPS rates are related
7 solely to BPA's sales of surplus power after the inception of the Slice product and not to sales of
8 requirements power. The expenses and revenues from such sales are included in the Non-Slice
9 cost pool. See TRM section 2.2.3.

10
11 Any bad debt expense associated with a sale to a customer that purchases power at only the PF or
12 IP rate will be included for purposes of the Composite Cost Pool True-Up. The allocation to the
13 Composite cost pool of any bad debt expense associated with a sale to a customer that purchases
14 power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both
15 the IP rate and the FPS rate, will be contingent on the facts and circumstances of the particular
16 instance of a full or partial non-payment of a power bill.

17
18 Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up
19 purposes if Slice customers paid for the bad debt expense through their Slice True-Up
20 Adjustment Charge.

21 22 **7.2.9 Settlement or Judgment Amounts**

23 BPA payments or receipts of money related to settlements and judgments will be allocated on a
24 case-by-case basis to either the Composite cost pool or the Non-Slice cost pool. If an amount
25 (payment or receipt) is accounted for in BPA's actual audited financial reports for any given
26 fiscal year (which are produced after rates are set), BPA will determine whether such amount

1 will be included or excluded for Composite Cost Pool True-Up purposes. Such a determination
2 will be made based on the principle of cost causation. See TRM section 2.1.

4 **7.2.10 Transmission Costs for Designated BPA System Obligations**

5 Transmission and Ancillary Services expenses are allocated between the Composite cost pool
6 and the Non-Slice cost pool, as specified on TRM Table 2A.

7
8 The Transmission and Ancillary Services expenses associated with Designated BPA System
9 Obligations are allocated to the Composite cost pool. Such Transmission and Ancillary Services
10 expenses are not subject to the Composite Cost Pool True-Up.

11
12 Transmission reservations are set aside for non-discretionary obligations (*i.e.*, Designated BPA
13 System Obligations). Since Power Services does not know the actual amounts of transmission
14 usage until the preschedule period for such obligations, the transmission reservations for those
15 obligations are purchased based on the maximum need for the year. Therefore, it is appropriate
16 to include the forecast cost of the reservations for Designated BPA System Obligations in the
17 Composite Cost Pool, and such costs are not subject to the Composite Cost Pool True-Up.

18
19 Any revenues from the resale of transmission that appear to be the result of BPA sales of unused
20 transmission inventory associated with set-aside transmission will be excluded for Composite
21 Cost Pool True-Up purposes. Such revenues are excluded from the Composite Cost Pool
22 True-Up to be consistent with the principle of no Composite Cost Pool True-Up of transmission
23 expenses for Designated BPA System Obligations. Since the cost of additional transmission
24 purchased (or of using non-Slice transmission inventory) to serve Designated BPA System
25 Obligations in excess of what was forecast in the ratesetting process is not included in the

1 Composite Cost Pool True-Up, revenues from sales of surplus transmission inventory also are
2 excluded from the Composite Cost Pool True-Up.

4 **7.2.11 Transmission Loss Adjustment**

5 A transmission loss adjustment is included in the Composite cost pool. Without such an
6 adjustment, Slice customers would pay not only for real power losses (through loss return
7 schedules to BPA) on the transmission of their Slice purchase, but also a proportionate share of
8 losses on the transmission of non-Slice products. See section 3.1.3.1 for an explanation of the
9 calculation of this credit.

10
11 The transmission loss adjustment is not subject to the Composite Cost Pool True-Up.

13 **7.2.12 Resource Support Services Revenue Credit**

14 A credit for RSS revenue is included in the Composite cost pool. The credit is for revenues
15 earned by uses of capacity to support resources that receive RSS. See section 3.1.2.1. This
16 revenue credit is not subject to the Composite Cost Pool True-Up.

18 **7.2.13 Tier 2 Rate Adjustments**

19 Tier 2 rate adjustments are ratesetting adjustments to the Composite cost pool to reflect a share
20 of expenses that are incurred by Power Services allocable to all power sold. See section 3.1.4.
21 There are three types of rate adjustments: the Tier 2 overhead cost adder, the Tier 2 risk adder,
22 and the Tier 2 transmission scheduling service cost adder.

23
24 The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by Power
25 Services. See section 3.1.7.1. The Tier 2 overhead cost adder is included in the Composite cost

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

3
4 The Tier 2 risk adder is an adjustment for any risks associated with costs of resources that Power
5 Services acquires for service to Tier 2 load. This adjustment is zero for the FY 2014-2015 rate
6 period because no risk mitigation treatment is necessary. See section 3.1.7.4. This adjustment is
7 not subject to the Composite Cost Pool True-Up.

8
9 The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative costs
10 incurred by Power Services. For a description of this adjustment, see section 3.1.7.2. The
11 forecast of this adjustment is included in the RSS revenue credit. This adjustment is not subject
12 to the Composite Cost Pool True-Up.

13 14 **7.2.14 Residential Exchange Program Expense**

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

19 20 **7.2.15 Non-Treaty Storage Agreement (NTSA) Annual Financial Settlements**

21 The NTSA is an agreement between BPA and B.C. Hydro that allows water transactions to be
22 financially settled between BPA and B.C. Hydro. The NTSA provides two mechanisms to settle
23 the transaction benefits, which BPA designates as a system obligation: energy deliveries during
24 the year or a financial settlement based on the August 31 balance at the end of the year.
25 Financial settlements in a fiscal year and the financial accrual amount recorded for the month of
26 September in a fiscal year are charged or credited to power purchases, and Slice customers pay

1 their share of the charge or receive their share of the credit through the Composite Cost Pool
2 True-Up Table.

3
4 **7.3 Slice Cost Pool True-Up**

5 The Slice Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the
6 Slice Cost Pool, which is described in TRM section 2.72. Calculation of the Annual Slice Cost
7 Pool True-Up is described in GRSP II.W.2 and shown in GRSP Table H. Slice expenses and
8 credits are forecast to be zero in FY 2014-2015. If there are any actual Slice expenses and
9 credits incurred during the rate period, such expenses and credits will be subject to the Slice Cost
10 Pool True-Up.

1 **8. AVERAGE SYSTEM COSTS**

2 **8.1 Overview of Average System Cost (ASC) and the Residential Exchange**
3 **Program (REP)**

4 The REP is described in section 2.1.2. One of the components of the REP is the participating
5 utilities' ASCs, which are determined in a separate ASC Review Process that BPA conducts
6 pursuant to the substantive and procedural requirements of the 2008 ASC Methodology
7 (ASCM). *See* 2008 ASCM, 18 C.F.R. § 301, *et seq.* The 2008 ASCM is an administrative rule
8 that governs BPA's calculation of ASCs. The Federal Energy Regulatory Commission granted
9 final approval to the 2008 ASCM on September 4, 2009.

10
11 As introduced in section 1.2.2, BPA is implementing the 2012 REP Settlement in rates for
12 FY 2014–2015. The Settlement establishes a fixed stream of REP benefits that are payable to
13 the IOUs beginning in FY 2012 and ending in FY 2028. Individual IOU REP benefit
14 determinations under the Settlement will continue as under the traditional REP. That is, BPA
15 will compare the IOUs' respective ASCs with their PF Exchange rates and, if the difference is
16 positive, multiply the difference by the IOUs' exchange loads. IOUs' ASCs and exchange loads
17 for FY 2014–2015 are needed to determine the REP benefits provided to individual IOU
18 participants consistent with the Settlement. Similarly, for the two COUs participating in the
19 REP, BPA will compare their respective ASCs with their PF Exchange rates and, if the
20 difference is positive, multiply the difference by their exchange loads. The COU REP benefits
21 are in addition to the fixed stream of IOU REP benefits under the Settlement. For a forecast of
22 individual utility annual REP benefit payments for FY 2014–2015, see Study Table 6.

23
24 **8.2 ASC Determinations**

25 A utility's ASC is calculated by dividing the utility's allowable resource costs (Contract System
26 Cost) by its allowable load (Contract System Load). The quotient is the utility's ASC (\$/MWh).
27 Contract System Cost is the sum of the utility's allowable generation-related and transmission-

1 related costs and overheads. Contract System Load is calculated as the total retail sales of a
2 utility, as measured at the meter, plus distribution losses, less any NLSLs, if applicable.

3
4 The ASCs used in the BP-14 Final Proposal were determined in Final ASC Reports published on
5 July 24, 2013. The Final ASC Reports reflect the utilities' ASCs for the BP-14 rate period.
6 Final ASC Reports were issued for eight utilities: Avista Utilities, Idaho Power Company,
7 NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark County
8 PUD, and Snohomish County PUD.

9
10 Under the 2008 ASCM, the actual ASC for each utility may change if the utility adds a new
11 resource, retires an existing resource, or adds an NLSL. The revised ASC takes effect in the
12 month after a new resource comes on line, an existing resource is retired, or a new NLSL begins
13 taking service.

14
15 Under the 2012 REP Settlement, participating IOUs agreed not to submit ASC revisions based
16 on new resources coming on line during the Exchange Period (the Exchange Period is identical
17 to the rate period). Under the 2012 REP Settlement, the ASCs that are effective on the first day
18 of the rate period will persist throughout the Exchange Period. Therefore, "day-one" ASCs have
19 been developed for use in establishing rates under the REP Settlement.

20
21 Three utilities have new resources that were scheduled to begin operation prior to the start of the
22 Exchange Period. For all three utilities, the new resources began operation prior to the
23 completion of the Final ASC Reports. Therefore, the day-one ASCs used for the BP-14 Final
24 Proposal include the costs of these new resources. The day-one ASCs are shown in
25 Documentation Table 8.2.

1 **8.3 BP-14 Residential and Farm Exchange Loads**

2 REP exchange loads are defined as a utility’s qualifying residential and farm consumer loads as
3 determined in accordance with the utility’s Residential Purchase and Sales Agreement or
4 Residential Exchange Program Settlement Implementation Agreement.

5
6 Residential Load is determined in the BP-14 ratemaking process pursuant to the terms of the
7 2012 Settlement. Under the Settlement, participating IOUs agreed to use a two-year historical
8 average for determining the monthly exchange load used to calculate REP benefits, referred to as
9 Residential Load. For the BP-14 rate period, the historical years are calendar year (CY) 2011
10 and CY 2012. The monthly loads applicable to both years of the BP-14 rate period are shown in
11 GRSP I.L.S., Table E.

12
13 For the COUs, the FY 2014–2015 exchange load forecasts are based on the exchange load
14 information provided by the COUs in the ASC Review Process. Each COU’s exchange load
15 forecast is adjusted for the COU’s Tier 1 percentage, as required by the TRM. The Tier 1
16 percentage is defined as BPA’s forecast percentage of the COU’s load that is expected to be
17 served by purchases of power at Tier 1 rates from BPA and from the COU’s Existing Resources
18 for CHWM. COU REP benefits will be paid on actual residential and farm sales as adjusted by
19 the Tier 1 percentage for each COU, as submitted after the conclusion of each month during the
20 rate period.

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POWER RATES TABLES

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Table 1: Rate Period High Water Marks for FY 2014-2015

| Table of RHWMs for FY 2014–FY 2015 | | |
|---|---|---------------------|
| A | B | C |
| | Preference Customer | RHWM aMW |
| 1) | Albion, City of | 0.400 |
| 2) | Alder Mutual Light Company | 0.55 |
| 3) | Ashland, City of | 21.157 |
| 4) | Asotin County PUD | 0.604 |
| 5) | Bandon, City of | 7.671 |
| 6) | Benton County PUD | 202.424 |
| 7) | Benton Rural Electric Association | 67.011 |
| 8) | Big Bend Electric Cooperative, Inc. | 61.449 |
| 9) | Blachly-Lane Electric Cooperative | 17.69 |
| 10) | Blaine, City of | 8.783 |
| 11) | Bonners Ferry, City of | 5.342 |
| 12) | Burley, City of | 14.123 |
| 13) | Canby Utility | 20.394 |
| 14) | Cascade Locks, City of | 2.61 |
| 15) | Central Electric Cooperative, Inc. | 82.192 |
| 16) | Central Lincoln People’s Utility District | 157.326 |
| 17) | Centralia, City of | 24.473 |
| 18) | Cheney, City of | 15.883 |
| 19) | Chewelah, City of | 2.856 |
| 20) | Clallam County PUD No. 1 | 76.345 |
| 21) | Clark Public Utilities | 319.822 |
| 22) | Clatskanie People’s Utility District | 93.968 |
| 23) | Clearwater Power Company | 24.263 |
| 24) | Columbia Basin Electric Cooperative, Inc. | 12.169 |
| 25) | Columbia Power Cooperative Association | 3.248 |
| 26) | Columbia River People’s Utility District | 60.605 |
| 27) | Columbia Rural Electric Cooperative, Inc. | 37.85 |
| 28) | Consolidated Irrigation District #19 | 0.229 |
| 29) | Consumers Power, Inc. | 45.864 |

| Table of RHWMs for FY 2014–FY 2015 | | |
|---|---|---------------------|
| A | B | C |
| | Preference Customer | RHWM aMW |
| 30) | Coos-Curry Electric Cooperative, Inc. | 41.046 |
| 31) | Coulee Dam, Town of | 2.033 |
| 32) | Cowlitz County PUD | 551.489 |
| 33) | Declo, City of | 0.36 |
| 34) | DOE National Energy Technology Laboratory | 0.460 |
| 35) | DOE Richland | 28.494 |
| 36) | Douglas Electric Cooperative, Inc. | 19.087 |
| 37) | Drain, City of | 2.453 |
| 38) | East End Mutual Electric Co., Ltd. | 2.698 |
| 39) | Eatonville, Town of | 3.382 |
| 40) | Ellensburg, City of | 24.082 |
| 41) | Elmhurst Mutual Power & Light Company | 32.372 |
| 42) | Emerald People’s Utility District | 52.664 |
| 43) | Energy Northwest | 2.879 |
| 44) | Eugene Water and Electric Board | 252.144 |
| 45) | Fairchild Air Force Base | 7.324 |
| 46) | Fall River Rural Electric Cooperative, Inc. | 33.268 |
| 47) | Farmers Electric Company | 0.51 |
| 48) | Ferry County PUD No. 1 | 11.714 |
| 49) | Flathead Electric Cooperative, Inc. | 167.518 |
| 50) | Forest Grove, City of | 26.986 |
| 51) | Franklin County PUD No. 1 | 117.841 |
| 52) | Glacier Electric Cooperative, Inc. | 21.406 |
| 53) | Grant County PUD No. 2 – Grand Coulee | 5.213 |
| 54) | Grays Harbor County PUD No. 1 | 131.764 |
| 55) | Harney Electric Cooperative, Inc. | 22.847 |
| 56) | Hermiston, City of | 12.991 |
| 57) | Heyburn, City of | 4.837 |
| 58) | Hood River Electric Cooperative | 13.153 |
| 59) | Idaho County Light & Power Coop. | 6.239 |
| 60) | Idaho Falls Power | 79.888 |
| 61) | Inland Power & Light Company | 108.191 |

| Table of RHWMs for FY 2014–FY 2015 | | |
|---|---|---------------------|
| A | B | C |
| | Preference Customer | RHWM aMW |
| 62) | Jefferson County PUD No. 1 | 45.361 |
| 63) | Kittitas County PUD No. 1 | 9.743 |
| 64) | Klickitat County PUD | 36.812 |
| 65) | Kootenai Electric Cooperative, Inc. | 51.212 |
| 66) | Lakeview Light & Power | 33.481 |
| 67) | Lane Electric Cooperative, Inc. | 29.224 |
| 68) | Lewis County PUD No. 1 | 114.207 |
| 69) | Lincoln Electric Cooperative, Inc. | 14.632 |
| 70) | Lost River Electric Cooperative, Inc. | 9.566 |
| 71) | Lower Valley Energy | 86.396 |
| 72) | Mason County PUD No. 1 | 9.024 |
| 73) | Mason County PUD No. 3 | 80.262 |
| 74) | McCleary, City of | 4.191 |
| 75) | McMinnville Water and Light | 104.659 |
| 76) | Midstate Electric Cooperative, Inc. | 46.941 |
| 77) | Milton-Freewater, City of | 10.585 |
| 78) | Milton, City of | 7.468 |
| 79) | Minidoka, City of | 0.119 |
| 80) | Mission Valley Power | 38.11 |
| 81) | Missoula Electric Cooperative, Inc. | 27.098 |
| 82) | Modern Electric Water Company | 26.394 |
| 83) | Monmouth, City of | 8.398 |
| 84) | Nespelem Valley Electric Cooperative, Inc. | 5.906 |
| 85) | Northern Lights, Inc. | 36.078 |
| 86) | Northern Wasco County PUD | 65.035 |
| 87) | Ohop Mutual Light Company | 10.201 |
| 88) | Okanogan County Electric Coop, Inc. | 6.556 |
| 89) | Okanogan County PUD No. 1 | 49.152 |
| 90) | Orcas Power and Light Cooperative | 24.837 |
| 91) | Oregon Trail Electric Consumers Cooperative, Inc. | 81.614 |
| 92) | Pacific County PUD No. 2 | 36.479 |
| 93) | Parkland Light and Water Company | 14.127 |

| Table of RHWMs for FY 2014–FY 2015 | | |
|---|---|---------------------|
| A | B | C |
| | Preference Customer | RHWM aMW |
| 94) | Pend Oreille County PUD No. 1 | 29.132 |
| 95) | Peninsula Light Company, Inc. | 72.285 |
| 96) | Plummer, City of | 3.962 |
| 97) | Port Angeles, City of | 85.836 |
| 98) | Port of Seattle | 17.35 |
| 99) | Raft River Rural Electric Cooperative, Inc. | 38.224 |
| 100) | Ravalli County Electric Cooperative, Inc. | 18.592 |
| 101) | Richland, City of | 101.564 |
| 102) | Riverside Electric Company | 2.382 |
| 103) | Rupert, City of | 9.462 |
| 104) | Salem Electric | 39.553 |
| 105) | Salmon River Electric Cooperative | 31.52 |
| 106) | Seattle City Light | 526.096 |
| 107) | Skamania County PUD No. 1 | 15.973 |
| 108) | Snohomish County PUD No. 1 | 802.401 |
| 109) | Soda Springs, City of | 3.07 |
| 110) | South Side Electric, Inc. | 6.793 |
| 111) | Springfield Utility Board | 101.126 |
| 112) | Steilacoom, Town of | 4.828 |
| 113) | Sumas, City of | 3.658 |
| 114) | Surprise Valley Electric Corp. | 16.5 |
| 115) | Tacoma Public Utilities | 404.068 |
| 116) | Tanner Electric Cooperative | 11.078 |
| 117) | Tillamook People’s Utility District | 56.263 |
| 118) | Troy, City of | 2.046 |
| 119) | U.S. Dept of the Navy – Bremerton | 30.587 |
| 120) | U.S. Dept of the Navy – Everett | 1.534 |
| 121) | U.S. Dept. of the Navy – Bangor | 20.506 |
| 122) | Umatilla Electric Cooperative | 113.695 |
| 123) | Umpqua Indian Utility Cooperative | 4.131 |
| 124) | United Electric Cooperative, Inc. | 30.102 |
| 126) | Vera Water & Power | 27.27 |

| Table of RHWMs for FY 2014–FY 2015 | | |
|---|--|---------------------|
| A | B | C |
| | Preference Customer | RHWM aMW |
| 127) | Vigilante Electric Cooperative, Inc. | 19.232 |
| 128) | Wahkiakum County PUD No. 1 | 5.026 |
| 129) | Wasco Electric Cooperative, Inc. | 13.452 |
| 130) | Weiser, City of | 6.355 |
| 131) | Wells Rural Electric Company | 96.171 |
| 132) | West Oregon Electric Cooperative, Inc. | 8.642 |
| 133) | Whatcom County PUD No. 1 | 26.945 |
| 134) | Yakama Power | 9.963 |
| | Total | 7115.875 |

Table 2: Overview of BP-14 Final Proposal Rates

Tiered PF Rate Summary

| | A | B | C | D |
|----|---|--------------|---------------|---------------|
| 1 | | | % above BP-12 | |
| 2 | Unbifurcated PF | \$ 41.83 | 7.6% | |
| 3 | PF Public (Tier 1 + Tier 2) | \$ 32.80 | 8.4% | |
| 4 | PF Exchange (IOU) | \$ 59.13 | 8.9% | |
| 5 | IP with 7(b)(3) | \$ 38.97 | 7.3% | |
| 6 | NR | \$ 77.65 | 11.7% | |
| 7 | | | | |
| 8 | | | | |
| 9 | Annual Average \$ (1000s)..... | BP-12 | BP-14 | Change |
| 10 | Composite Rate Revenues..... | \$ 2,262,417 | \$ 2,313,762 | 2.3% |
| 11 | Non-Slice Rate Revenues..... | \$ (325,256) | \$ (259,448) | 20.2% |
| 12 | Slice Rate Revenues..... | \$ - | \$ - | |
| 13 | Load Shaping Rate Revenues..... | \$ (14,083) | \$ 13,107 | -193.1% |
| 14 | Demand Rate Revenues | \$ 60,101 | \$ 43,171 | -28.2% |
| 15 | Tier 1 Revenue Requirement..... | \$ 1,983,178 | \$ 2,110,593 | 6.4% |
| 16 | Tier 2 Revenue Requirement..... | \$ 16,363 | \$ 15,636 | |
| 17 | Value of Slice Surplus..... | \$ (162,043) | \$ (120,207) | 25.8% |
| 19 | Lookback Return (credit)..... | \$ (76,538) | \$ (76,538) | |
| 20 | Net Power Cost to All PF..... | \$ 1,760,961 | \$ 1,929,483 | 9.6% |
| 21 | Annual PF Load (w/firm Slice) (GWh)..... | 60,702 | 61,158 | 0.8% |
| 22 | PF Average Net Cost (\$/MWh)..... | 29.01 | 31.55 | 8.8% |
| 23 | | | | |
| 24 | Tier 1 Average Net Cost (\$/MWh)..... | 28.90 | 31.50 | 9.0% |
| 25 | Tier 2 (\$/MWh)..... | 48.11 | 39.86 | -17.1% |
| 26 | | | | |
| 27 | | | | |
| 28 | Slice Sales..... | BP-12 | BP-14 | Change |
| 29 | Composite+Slice..... | \$ 629,081 | \$ 626,613 | |
| 30 | Tier 1 Average Cost (\$/MWh)..... | 37.43 | 37.69 | 0.7% |
| 31 | Value of Slice Surplus+Credits..... | \$ (183,325) | \$ (140,935) | |
| 32 | Net Cost of Slice Power..... | \$ 445,756 | \$ 485,678 | |
| 33 | Tier 1 Average Net Cost (\$/MWh)..... | 26.52 | 29.21 | 10.1% |
| 34 | | | | |
| 35 | | | | |
| 36 | Non-Slice Sales..... | BP-12 | BP-14 | Change |
| 37 | Composite+NonSlice+Shape+Demand..... | \$ 1,354,050 | \$ 1,484,061 | |
| 38 | Tier 1 Average Cost (\$/MWh)..... | 30.98 | 33.32 | 7.5% |
| 39 | Credits..... | \$ (55,256) | \$ (55,810) | |
| 40 | Net Cost of Non-Slice Power..... | \$ 1,298,794 | \$ 1,428,251 | |
| 41 | Tier 1 Average Net Cost (\$/MWh)..... | 29.72 | 32.07 | 7.9% |
| 42 | | | | |
| 43 | | | | |
| 44 | Tiered PF Rate Components..... | BP-12 | BP-14 | Change |
| 45 | Composite Rate (\$/ pct/month)..... | \$ 1,952,168 | \$ 1,961,053 | 0.5% |
| 46 | Non-Slice Rate (\$/ pct/month)..... | \$ (388,748) | \$ (301,568) | -22.4% |

Table 3: Revenues at Current Rates

| | B | C | D | E | F | G | H | I | J | K |
|----|--|---|---|---|--------------------|--------------|--------------------|--------------|--------------------|--------------|
| 1 | Revenues at Current Rates | | | | 2013 | 2013 | 2014 | 2014 | 2015 | 2015 |
| 2 | Category | | | | \$ (000's) | aMW | \$ (000's) | aMW | \$ (000's) | aMW |
| 3 | Composite Revenue | | | | \$2,277,224 | 5,052 | \$2,286,922 | 6,982 | \$2,296,054 | 7,011 |
| 4 | Non-Slice Revenue | | | | (\$328,205) | - | (\$330,200) | - | (\$332,018) | - |
| 5 | Slice | | | | \$0 | 2,072 | \$0 | - | \$0 | - |
| 6 | Load Shaping Revenue | | | | (\$19,379) | (29) | (\$23,106) | (54) | (\$439) | 19 |
| 7 | Demand Revenue | | | | \$42,486 | - | \$58,325 | - | \$59,756 | - |
| 8 | Irrigation Rate Discount | | | | (\$19,305) | - | (\$18,812) | - | (\$18,812) | - |
| 9 | Low Density Discount | | | | (\$32,077) | - | (\$22,047) | - | (\$22,492) | - |
| 10 | Tier 2 | | | | \$24,055 | 56 | \$7,097 | 18 | \$33,304 | 75 |
| 11 | RSS (Non-Federal) | | | | \$698 | - | \$243 | - | \$243 | - |
| 12 | PF customers (CHWM) sub-total | | | | \$1,945,498 | 7,151 | \$1,958,422 | 6,945 | \$2,015,596 | 7,105 |
| 13 | DSIs sub-total | | | | \$101,673 | 320 | \$99,190 | 312 | \$99,190 | 312 |
| 14 | FPS sub-total | | | | \$2,781 | 8 | \$3,052 | 8 | \$3,119 | 9 |
| 15 | Short-term market sales sub-total | | | | \$430,832 | 1,874 | \$322,152 | 1,661 | \$340,317 | 1,654 |
| 16 | Long Term Contractual Obligations sub-total | | | | \$33,722 | 62 | \$29,865 | 59 | \$29,865 | 74 |
| 17 | Canadian Entitlement Return | | | | \$0 | 505 | \$0 | 500 | \$0 | 475 |
| 18 | Renewable Energy Certificates sub-total | | | | \$1,132 | - | \$1,061 | - | \$1,107 | - |
| 19 | Other Sales sub-total | | | | (\$4,986) | - | \$0 | - | \$0 | - |
| 20 | Gross Sales | | | | \$2,510,651 | 9,920 | \$2,413,742 | 9,485 | \$2,489,194 | 9,629 |
| 21 | Miscellaneous Revenues | | | | \$29,094 | 178 | \$32,597 | 178 | \$32,621 | 178 |
| 22 | Generation Inputs / Inter-business line | | | | \$142,432 | 9 | \$119,186 | 9 | \$121,934 | 9 |
| 23 | 4(h)(10)(c) | | | | \$86,649 | - | \$97,173 | - | \$92,996 | - |
| 24 | Colville and Spokane Settlements | | | | \$4,600 | - | \$4,600 | - | \$4,600 | - |
| 25 | Treasury Credits | | | | \$91,249 | - | \$101,773 | - | \$97,596 | - |
| 26 | Augmentation Power Purchase total | | | | \$0 | - | \$6,198 | 21 | \$94,913 | 318 |
| 27 | Balancing Power Purchase sub-total | | | | \$119,664 | 199 | \$27,421 | 156 | \$26,720 | 145 |
| 28 | Other Power Purchase total | | | | \$68,885 | 139 | \$40,340 | 87 | \$24,869 | 74 |
| 29 | Power Purchases | | | | \$188,549 | 338 | \$73,958 | 264 | \$146,501 | 537 |

Table 4: Revenues at Proposed Rates

| | B | C | D | E | F | G | H | I | J | K |
|----|--|---|---|---|--------------------|--------------|--------------------|--------------|--------------------|--------------|
| 1 | Revenues at Proposed Rates | | | | 2013 | 2013 | 2014 | 2014 | 2015 | 2015 |
| 2 | Category | | | | \$ (000's) | aMW | \$ (000's) | aMW | \$ (000's) | aMW |
| 3 | Composite Revenue | | | | \$2,277,224 | 5,052 | \$2,308,843 | 6,982 | \$2,318,682 | 7,011 |
| 4 | Non-Slice Revenue | | | | (\$328,205) | - | (\$258,691) | - | (\$260,204) | - |
| 5 | Slice | | | | \$0 | 2,072 | \$0 | - | \$0 | - |
| 6 | Load Shaping Revenue | | | | (\$19,379) | (29) | \$3,422 | (54) | \$22,791 | 19 |
| 7 | Demand Revenue | | | | \$42,486 | - | \$42,954 | - | \$43,388 | - |
| 8 | Irrigation Rate Discount | | | | (\$19,305) | - | (\$18,816) | - | (\$18,816) | - |
| 9 | Low Density Discount | | | | (\$32,077) | - | (\$35,303) | - | (\$36,361) | - |
| 10 | Tier 2 | | | | \$24,055 | 56 | \$5,502 | 18 | \$25,769 | 75 |
| 11 | RSS (Non-Federal) | | | | \$698 | - | \$504 | - | \$757 | - |
| 12 | PF customers (CHWM) sub-total | | | | \$1,945,498 | 7,151 | \$2,048,415 | 6,945 | \$2,096,006 | 7,105 |
| 13 | DSIs sub-total | | | | \$101,673 | 320 | \$106,510 | 312 | \$106,510 | 312 |
| 14 | Pre-Subscription (FPS) sub-total | | | | \$2,781 | 8 | \$3,052 | 8 | \$3,119 | 9 |
| 15 | Short-term market sales sub-total | | | | \$430,832 | 1,874 | \$322,152 | 1,661 | \$340,317 | 1,654 |
| 16 | Long Term Contractual Obligations sub-total | | | | \$33,722 | 62 | \$29,865 | 59 | \$29,865 | 74 |
| 17 | Canadian Entitlement Return | | | | \$0 | 505 | \$0 | 500 | \$0 | 475 |
| 18 | Renewable Energy Certificates sub-total | | | | \$1,132 | - | \$1,061 | - | \$1,107 | - |
| 19 | Other Sales sub-total | | | | (\$4,986) | - | \$0 | - | \$0 | - |
| 20 | Gross Sales | | | | \$2,510,651 | 9,920 | \$2,511,055 | 9,485 | \$2,576,924 | 9,629 |
| 21 | Miscellaneous Revenues | | | | \$29,094 | 178 | \$29,689 | 178 | \$29,953 | 178 |
| 22 | Generation Inputs / Inter-business line | | | | \$142,432 | 9 | \$117,696 | 9 | \$112,910 | 9 |
| 23 | 4(h)(10)(c) | | | | \$86,649 | - | \$97,173 | - | \$92,996 | - |
| 24 | Colville and Spokane Settlements | | | | \$4,600 | - | \$4,600 | - | \$4,600 | - |
| 25 | Treasury Credits | | | | \$91,249 | - | \$101,773 | - | \$97,596 | - |
| 26 | Augmentation Power Purchase sub-total | | | | \$0 | - | \$6,198 | 21 | \$94,913 | 318 |
| 27 | Balancing Power Purchase sub-total | | | | \$119,664 | 199 | \$27,421 | 156 | \$26,720 | 145 |
| 28 | Other Power Purchase sub-total | | | | \$68,885 | 139 | \$40,340 | 87 | \$24,869 | 74 |
| 29 | Power Purchases | | | | \$188,549 | 338 | \$73,958 | 264 | \$146,501 | 537 |

Table 5: Adjustments to Financial Reserves Base Amount

| | A | B | C | D | E | F |
|----|---|---------|--------------------|------------------------------|--------------------|-----------------------|
| 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 | | | | | | |
| 19 | Total: \$ (74,655,047.39) | | | | | |
| 20 | | | | | | |
| 21 | Reasons for adjustments | | | | | |
| 22 | 1) BPA's receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002, | | | | | |
| 23 | 2) BPA's receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002, | | | | | |
| 24 | 3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002. | | | | | |
| 25 | | | | | | |
| 26 | Base amount of financial reserves = | | | \$ | 495,600,000 | |
| 27 | | | | | | |
| 28 | Adjustment to the base amount of financial reserves = | | | \$495,600,000 + \$74,655,047 | | |
| 29 | | | | | | |
| 30 | Resulting amount of financial reserves = | | | \$ | 570,255,047 | |
| 31 | | | | | | |
| 32 | Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount. | | | | | |
| 33 | 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

| | A | B | C | D |
|----|--------------------------------------|----------------|----------------|-------------------|
| 1 | Residential Exchange Benefits | FY 2014 | FY 2015 | |
| 2 | Avista Corporation | \$ 8,053 | \$ 8,053 | |
| 3 | Idaho Power Company | \$ 3,001 | \$ 3,001 | |
| 4 | NorthWestern Energy, LLC | \$ 5,063 | \$ 5,063 | |
| 5 | PacifiCorp | \$ 34,741 | \$ 34,741 | |
| 6 | Portland General Electric Company | \$ 49,913 | \$ 49,913 | |
| 7 | Puget Sound Energy, Inc. | \$ 96,728 | \$ 96,728 | |
| 8 | Net IOU Exchange | \$ 197,500 | \$ 197,500 | \$ 197,500 |
| 9 | Refund Amt | \$ 76,538 | \$ 76,538 | \$ 76,538 |
| 10 | | | | |
| 11 | Clark Public Utilities | \$ 3,019 | \$ 2,998 | |
| 12 | Franklin | \$ - | \$ - | |
| 13 | Snohomish County PUD No 1 | \$ - | \$ - | |
| 14 | Net COU Exchange | \$ 3,019 | \$ 2,998 | \$ 3,008 |
| 15 | | | Total | \$ 277,046 |

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-14 energy rates, which become the energy rates used in the IP-14 rate for BPA's direct-service industry (DSI) customers.

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-14 demand and energy rates before any 7(b)(2) or floor rate adjustments are applied.

2.2 “Typical Margin”

The typical margin is based generally on the overhead costs that consumer-owned utilities add to the cost of power in setting their retail industrial rates; see section 2.3 below.

2.3 Margin Determination Factors

7(c)(2)(A) – 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.

7(c)(2)(B) – 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.

7(c)(2)(C) – 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

The 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.

3.1 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 A 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 A. These results were used in the BP-12 rate case. The weighted industrial margin based on this margin study for the BP-12 rate case was 0.685 mills/kWh.

4. THE INDUSTRIAL MARGIN FOR THE BP-14 RATE CASE

BPA did not conduct a new industrial margin survey for the BP-14 rate case. Because such a brief period had passed since the last margin survey (about 18 months), and a concern that PPC might find it burdensome to undertake a significant involvement in another margin survey in early 2012, BPA contacted PPC (representing public power) and Alcoa (a DSI customer) about the possibility of reaching an agreement to waive conducting the industrial margin survey in the BP-14 rate case. This led to a Memorandum of Understanding among PPC, Alcoa, and BPA to waive the industrial margin survey in this rate case. See Attachment B.

The BP-14 industrial margin is calculated by adding an inflation factor to the BP-12 rate case industrial margin, using two years' increase in the GDP Implicit Price Deflator. Accordingly, the BP-12 industrial margin, 0.685 mills/kWh, is multiplied by 1.035. The BP-14 industrial margin is 0.709 mills/kWh.

Attachment A

2012 Industrial Margin Study

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Attachment B

**Memorandum of Understanding
Waiver of Industrial Margin Survey 2014 BPA Rate Case**

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