2012 BPA Initial Rate Proposal

Power Rates Study

November 2010

BP-12-E-BPA-01

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POWER RATES STUDY

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TABLES

COMMONLY USED ACRONYMS AND SHORT FORMS

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 or Corps	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps or COE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	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
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	Hydro Simulation (computer model)
ICE	IntercontinentalExchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
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
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
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

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)
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
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
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
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION AND BACKGROUND

1.1 Power Rates Study Overview

The Power Rates Study (Study), formerly known as the Wholesale Power Rate Development Study, explains the processes and calculations used to develop the power rates and billing determinants for BPA's wholesale power products and services. The Study serves three primary purposes: (1) to demonstrate that the proposed rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute, (2) set rates consistent with agency policy; and (3) to demonstrate that the proposed rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period. The rate design process is illustrated in section 1 of the Power Rates Study Documentation (Documentation), BP-12-E-BPA-01A, and described further throughout this Study.

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

The results of the power rate development process, including rates for power products and services, plus general rate schedule provisions, appear in the Power Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-12-E-BPA-09. The revenues resulting from the rates developed herein are used by the Power Revenue Requirement Study in the Revised Revenue Test to test the adequacy of the rates in recovering expenses and supplying adequate cash to cover non-expense cash outlays. Power Revenue Requirement Study, BP-12-E-BPA-02, section 3.3.

1.2 Statutory and Legal Overview

The Northwest Power Act, 16 U.S.C. § 839, is the most prominent statute providing ratemaking directives to BPA. Section 7(a)(1) states:

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

> section 5 of the Flood Control Act of 1944 [16 U.S.C. § 825s], and the provisions of this chapter.

Section 7(a)(1) directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. The Bonneville Project Act of 1937 defines "periodically review and revise" as "not less frequently than once in every five years." The section also directs that rates recover all of the Administrator's costs, including the repayment of the Federal investment in the Federal Columbia River Power System. Rates are also to be in accord with two other statutes, the Transmission System Act and the Flood Control Act.

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

1.2.1 Cost of Service Analysis

Northwest Power Act sections 7(b)(1), 7(d), 7(f), and 7(g) provide guidance to BPA for allocating resource and other costs to load (rate) pools. That guidance is summarized below. See section 2.1 for a full discussion of the implementation of these sections of the Northwest Power Act in the Rate Analysis Model (RAM2012).

Section 7(b)(1) states:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c) of this title. Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads

> until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) of this title and then from other resources.

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

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

Section 7(d)(1) states:

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

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

Section 7(f) states:

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

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

Section 7(g) states:

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

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

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

1.2.2 Rate Directives

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

Section 7(c) in pertinent part states:

> The rate or rates applicable to direct service industrial customers shall be established for the period beginning July 1, 1985, 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) describes how BPA is to set the rate it charges DSI customers. It provides that the DSI rate will be set to be equitable in relation to retail industrial rates of consumer-owned utility (COU) customers. Section 7(c) provides guidance on how to establish and modify this equitable relationship.

> The [DSI rate] shall be based upon 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 but shall take into account the comparative size and character of the loads served, the

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

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

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

Section 7(c)(3) directs that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. The VOR is discussed in section 3.3.1.1. In summary, the result of section 7(c) is that the DSI rate is set equal to the applicable wholesale rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test. Because the DSI rate interacts with the PF rate and the NR rate, the three rates are determined simultaneously through a solution called the 7(c)(2) Delta. The determination and application of the 7(c)(2) Delta is discussed in section 2.2.2.3.

Section 7(b)(2) states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency

> customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes [five certain assumptions].

Section 7(b)(2) describes a rate test designed to ensure that preference customers' firm power rates are no higher than rates calculated using five certain assumptions that remove specified effects of the Northwest Power Act. If the 7(b)(2) rate test triggers, the preference customers are entitled to rate protection. The 7(b)(2) rate test and the determination of the amount of rate protection are discussed in section 2.2.3.

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

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

Section 7(b)(3) directs that the cost of any rate protection afforded to preference customers is borne by all other BPA Power sales. The rate protection does not extend to all PF customers; the public body, cooperative, and Federal agency customers receive the rate protection, but REP participants do not. Thus, to allow the cost reallocations due to the rate protection, the PF rate is bifurcated. The two resulting rates are the PF Public rate, which receives the rate protection, and the PF Exchange rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The rate protection amount is collected though additional charges included in rates for all non-PF Public sales. The reallocation of rate protection costs is discussed in section 2.2.1 and 2.2.3.1.

1.2.3 Rate Design

Section 7(e) states:

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

BPA rates must follow the ratesetting directives of section 7, but, as characterized in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue the Administrator collects from each class of customers, not the rate form. This section reserves rate design (how the revenue is collected) to the Administrator. Rate design is discussed in section 2.3.

1.3 Regional Dialogue Policy Overview

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

In October 2008, BPA offered contracts to all of its preference customers and investor-owned utilities. By December 5, 2008, all preference customers and three of seven investor-owned utilities (IOUs) signed the new contracts, which went into effect immediately. Power service under these contracts will commence at the start of fiscal year (FY) 2012, the first year of the rate period for which rates are being developed in this study.

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

1.3.1 Regional Dialogue Contract Product Descriptions

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

Load Following. The Load Following product supplies firm power to meet the customer's Total Retail Load (TRL), less any firm power supplied by the customer from any Dedicated Resources and any declared, metered "behind the meter" non-Federal resource amounts. The costs associated with the energy and capacity necessary to provide the Load Following service will be recovered through Tier 1 rate charges for load shaping and demand.

Block. The Block product provides a planned amount of firm power to meet a customer's planned annual Net Requirement load. To buy this product, the customer must have dedicated non-Federal resources, and the customer is responsible for using those resources dedicated to its TRL to meet any load in excess of its planned monthly BPA Block purchase. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand. No customers chose to purchase the Block only product in this first election period.

Slice/Block. The Slice/Block product provides a combined sale of two distinct power products: (1) firm power for a customer's net requirements load and an advance sale of surplus energy based on the generation shape of the Federal system, and (2) firm requirements power under a Block product. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand.

1.4 Tiered Rate Methodology

The TRM provides for a two-tiered PF rate design applicable to firm requirements power service for preference customers that signed a CHWM contract. The TRM establishes a predictable and durable means by which to calculate BPA's PF tiered rates for power deliveries beginning in FY 2012. The tiered rate design differentiates between the cost of service associated with Tier 1 System Resources and the cost associated with additional amounts of power sold by BPA to serve any remaining portion of a customer's Net Requirement, also referred to as Above-Rate Period High Water Mark (Above-RHWM) load. The tiering of rates is one of the final steps in the development of rates and does not alter the fundamental manner in which BPA allocates costs to the various rate pools under the Northwest Power Act. This Study describes the steps taken to tier the Priority Firm rates.

CHWMs, determined according to the TRM, are one basis (others are described later in this section) for determining how much of each customer's net requirement purchased from BPA is charged at Tier 1 rates and how much may be charged at Tier 2 rates. The CHWM for each customer will be calculated by BPA in FY 2011 and will be used to set each customer's initial eligibility to purchase power at Tier 1 rates. The CHWMs will be in the contract.

Related to the CHWM is the RHWM, which is an expression of the CHWM scaled to the expected output of resources identified as comprising the Tier 1 system. Because CHWMs will be determined based on the expected output of Tier 1 system resources during FY 2012-2013, RHWMs for this period are equal to CHWMs consistent with the TRM. Each customer's RHWM for FY 2012-2013 defines that customer's maximum eligibility to purchase at Tier 1 rates for the rate period, limited for Slice and Block customers by the purchaser's Annual Net Requirement, and for Load Following customers by the purchaser's Actual Net Requirement. The TRM specifies how rates will be developed that ensure, to the maximum extent possible, that customers purchasing at Tier 1 rates do not pay any of the costs of serving other customers' Above-RHWM load.

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

The TRM was established in the TRM-12 rate case in 2008 and the supplementary TRM-12S rate case in 2009. For further details, see BPA's Tiered Rate Methodology, TRM-12S-A-03, and related Records of Decision, TRM-12-A-01 and TRM-12S-A-01. Five changes to the TRM are being proposed in this BP-12 rate proceeding to address Unintended Consequences, defined in the TRM, that were discovered during this initial implementation of the TRM. The TRM defines the process required to make changes to address Unintended Consequences in sections 12 and 13.

1.5 Rate Options Supporting Regional Dialogue Products

1.5.1 Above-RHWM Load Service

A customer may choose to have its Above-RHWM load served as net requirements load by BPA at Tier 2 rates, consistent with the appropriate notice and commitment requirements, which can be found in the TRM. The Tier 2 rate alternatives currently available are the Tier 2 Load Growth rate and the Tier 2 Short-Term rate. The Tier 2 Vintage rate is a possible Tier 2 rate alternative that may be offered in the future. Additional information on the Tier 2 rate alternatives can be found in BPA's *Regional Dialogue Guidebook*. A description of rates for Tier 2 service can be found in section 3.1 of this document and in the PF-12 Rate Schedule.

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

1.5.2 Resource Support Services

BPA has developed a suite of Resource Support Services and related services for customers' non-Federal resources and for pricing service from BPA at Tier 2 rates. These services include Diurnal Flattening Service (DFS), Forced Outage Reserve Service (FORS), Secondary Crediting Service (SCS), Resource Remarketing Service (RRS), and Transmission Curtailment Management Service (TCMS). Depending on the type of resource and its output, RSS may be required to be purchased from either BPA or non-Federal sources for purposes of matching the resource to a planned shape and amount of load. These services enable BPA to cover the costs of following the variation between planned and actual customer resource amounts and to account for the impact that resource shapes and fluctuations have on BPA's cost to meet its customers' Net Requirement load. Additional information on the RSS suite of products can be found in section 3.1.1.3, BPA's *Regional Dialogue Guidebook*, and the GRSPs, BP-12-E-BPA-09.

1.6 Rate Period High Water Marks

Each customer's RHWM helps to define that customer's maximum eligibility to purchase at Tier 1 rates for the rate period. The RHWM is determined based on the customer's CHWM and the RHWM Tier 1 System Capability (RT1SC) . The determination of a customer's RHWM occurs outside of the rate case in the RHWM Process and is described in section 4.2.1 of the TRM. As noted in section 4.2 of the TRM, each customer's CHWM will be used as its RHWM for the FY 2012-2013 rate period. Because the CHWM will not be known until the CHWM Process is complete in FY 2011 (see TRM section 4.1), in this Study each customer's CHWM is represented by a Proxy RHWM. See section 1.6.1.1 for description of Proxy RHWM calculation. After the CHWM Process is complete, each customer's Proxy RHWM will be replaced with the CHWM established in the CHWM Process for calculation of final rates. In the event the CHWMs are not finalized in time to be included in the BP-12 Final Proposal, the best available estimate of the CHWM will be used as the FY 2012-2013 RHWM.

1.6.1 Proxy RHWMs

For all customers with CHWM contracts, Proxy RHWMs have been developed by calculating forecast CHWMs and then setting the Proxy RHWMs equal to the forecast CHWMs. The steps defined in section 4 of the TRM have been followed to the extent possible, given that many data elements in the CHWM calculation are not yet available or final. Where final data is not available, either a substitution or an estimate is used. Proxy RHWMs for FY 2012-2013 are listed in Table 1.

1.6.1.1 Calculating Proxy RHWMs

A forecast CHWM is developed in the following manner for each Existing Public customer. Eligible Load for each customer is estimated by using the March 2009 forecast of FY 2010 Total Retail Load (TRL), adjusted for New Large Single Loads (NLSLs), plus any estimated Provisional Load amount and minus any Existing Resources listed in Attachment C of the TRM. Provisional Load (see TRM section 4.1.3.1) amounts are based on an estimate of Path 2 Provisional Load amounts (general system load reduction). The Path 2 Provisional Load estimates are the difference between (i) the average of the Adjusted FY 2007-2008 Loads and

(ii) the March 2009 forecast of FY 2010 TRL adjusted for NLSLs, Existing Resources, and accumulated credited conservation. The accumulated credited conservation used is the sum of credited conservation for FY 2007-2010, with credited conservation in FY 2010 assumed to be equal to credited conservation in FY 2009. Path 1 Provisional Load amounts have not been estimated because there is insufficient information available to estimate specific consumer load reductions.

The Scaled Eligible Load for each customer is estimated by multiplying the Eligible Load derived as described above by the percentage derived by dividing (i) the Tier 1 System Firm Critical Output (T1SFCO) plus Augmentation by (ii) the sum of estimated Eligible Load for Existing Publics.

The Scaled Eligible Load adjusted for credited conservation is estimated by (i) adding to the estimated Scaled Eligible Load the sum of the credited conservation, as described above, and (ii) multiplying the amount resulting from step (i) by the percentage derived by dividing (a) the sum of the estimated Scaled Eligible Load for Existing Publics by (b) the sum of the estimated Scaled Eligible Load adjusted for credited conservation for Existing Publics.

1.6.1.2 Calculating Forecast CHWMs for New Publics Formed with Loads Previously Served by an Entity Other Than an Existing Public

A forecast CHWM is developed in the following manner for each New Public formed with loads previously served by an entity other than an Existing Public. The forecast of the New Public's TRL is adjusted for NLSLs and non-Federal resources for the fiscal year in which power deliveries under the New Public's CHWM Contract will begin. That load is multiplied by the percentage derived by dividing (i) the sum of the forecast CHWMs for Existing Customers derived in section 1.6.1.1 by (ii) the sum of the March 2009 forecast TRL, adjusted for NLSLs and Existing Resources listed in Attachment C of the TRM, for Existing Publics for the fiscal year in which power deliveries under the New Public's CHWM Contract will begin.

1.6.1.3 Setting Proxy RHWMs Equal to Forecast CHWMs

For all Public customers with CHWM contracts, the Proxy RHWM is set equal to the forecast CHWM. See TRM, TRM-12S-A-03, section 4.2.

1.6.2 RHWM Outputs

The RHWMs and related outputs of the RHWM Process, including RHWM Augmentation, RHWM Tier 1 System Capability, and forecast Net Requirements, are used to calculate billing determinants. Billing determinants impacted by the RHWMs, and therefore the Proxy RHWMs, include (1) a forecast of power sold at Load Shaping Rates, (2) the Tier 1 Cost Allocators (TOCAs), and (3) Unused RHWM. For the FY 2012-2013 rate period, the Above-RHWM load is not an output of the Proxy RHWM, as this amount was established when the Transition High Water Marks (THWM) were developed (see TRM section 4.3). For a description of how values calculated in the RHWM Process are used in the calculation of billing determinants, see section 3.1.5.

2. RATESETTING METHODOLOGY AND PROCESS

This initial proposal is developed assuming that a proposed Settlement of Litigation on REP, 7(b)(2) and Lookback issues is adopted. However, at this time it has not been determined whether the Administrator will adopt the Settlement. The ratemaking steps and rate modeling described in this section include both the steps assuming a settlement and the steps assuming no settlement. Most discussion is applicable to both assumptions. Where differences occur, the discussion notes the distinctions. The drafting of the Settlement Agreement was not concluded at the time this Initial Proposal was completed. The representations of the Settlement Agreement herein are at a point in time and are subject to change.

BPA's ratesetting process for power products and services under the Regional Dialogue contracts has three main steps:

(1) A Cost of Service Analysis (COSA) Step (see section 2.1) that allocates the various types of costs (categorized into resource or cost pools) to the various classes of customers (categorized into load or rate pools) using allocation factors calculated based on loads and resources.

(2) A Rate Directives Step (see section 2.2) that reallocates costs between rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act.

(3) A Rate Design Step (see section 2.3) that produces tiered PF Public rates that collect the PF Public revenue requirement determined in the Rate Directives Step. This step also implements the rate design for other non-tiered rates.

2.1 Cost of Service Analysis Step

The COSA assigns responsibility for ("allocates") BPA's power revenue requirement (grouped into resource pools, also called cost pools) to the various classes of service (grouped into load pools, also called rate pools) based on the resources used to serve those loads, in compliance with statutory directives governing BPA's ratemaking and in accordance with generally accepted ratemaking principles. The COSA and the other ratemaking steps are programmed into a spreadsheet model, RAM2012, for purposes of calculating power rates.

2.1.1 Description of Cost of Service Analysis Modeling

The COSA modeling uses disaggregated customer load data from the source data used to produce the Power Loads and Resources Study. See Power Rates Study Documentation, Table 2.1.1. The disaggregated load data are aggregated into the Priority Firm Power (PF) rate pool, (which consists of two sub-pools, the Priority Firm Public (PFp) rate pool and the Priority Firm Exchange (PFx) rate pool); the Industrial Firm Power (IP) rate pool; the New Resource Firm Power (NR) rate pool; and the Firm Power Products and Services (FPS) rate pool. See Documentation, Table 2.2.2. The rates charged for service to the various rate pools are associated with specific sections in the Northwest Power Act that describe how costs are to be allocated to those rate pools: the PF rates are section 7(b) rates; the IP rates are section 7(c) rates; and the NR and FPS rates are section 7(f) rates. See section 1.2.

After the load data is input into the RAM2012, the COSA modeling uses the disaggregated resource data from the source data used in the Power Loads and Resources Study. See Documentation, Table 2.1.2. The disaggregated resource data are aggregated into the resource pools specified by section 7 of the Northwest Power Act. These resource pools are the Federal base system (FBS) resource pool, the exchange resource pool, and the new resource pool. See Documentation, Table 2.2.2. The resources in the FBS and new resource pools are actual or planned resources that will be able to serve actual load during the rate period. The exchange resources are sized to be equal to the forecast of the eligible REP exchange load during the rate period. To calculate the eligible REP exchange load, the COSA modeling includes a test that determines which of the potential exchanging utilities have an Average System Cost (ASC) that is greater than the applicable Base PFx rate, see section 2.2.1, for the rate period. Those utilities with higher ASCs will be participating in the REP during the rate period. See Documentation, Table 2.1.3. In this way, the modeling determines the PFx load, the size of the exchange resource pool, and the costs of the exchange resources, the costs being the ASCs multiplied by the eligible exchange loads.

The aggregated load and resource data is used to calculate a load-resource balance for each year of the section 7(b)(2) rate test period (the FY 2012-2013 rate period plus the ensuing four years) and then to calculate energy allocation factors (EAFs) that the COSA modeling will use to apportion costs among rate pools. The EAFs are calculated based on the priorities of service from resource pools to rate pools specified in section 7 of the Northwest Power Act, and based on the principle of cost causation when section 7 does not provide guidance. Section 7(b)(1) directs BPA to allocate the cost of the FBS resources to the PF load pool first. When the FBS resources are not sufficient to serve all PFp and PFx loads, section 7(b)(1) directs BPA to serve the remaining load first with resources obtained by BPA under section 5(c) of the Northwest Power Act, that is, the exchange resources, and then with new resources, as needed. In this proposal, all of the FBS and a large portion of exchange resources are needed to serve PF loads; no new resources are needed. After all of the FBS resource costs and the portion of the exchange resource costs are allocated to the PF rate pool, section 7(f) of the Act directs BPA to allocate the cost of the remaining exchange resources and the cost of any other resources, new resources, to all remaining load.

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

Functionalization of costs between the generation and transmission functions is performed in the Power and Transmission Revenue Requirement Studies, and only the costs functionalized to the generation function are included in the power revenue requirement found in the COSA modeling (one exception to this is exchange resource costs; see section 2.1.3.2). As stated above, the exchange resource costs are calculated internal to the RAM2012. These exchange resource costs include transmission function costs. The exchange resource costs are functionalized in the COSA modeling so that only the generation portion of the exchange resource costs is subject to the power cost rate steps, and the transmission cost portion is then added back in after the Rate Directives Step is completed. In this way, the statutorily mandated power cost relationships between the various rate pools are maintained without being affected by the PFx transmission function costs.

In addition to exchange resource costs, the COSA modeling uses other costs that are internally generated by the RAM2012. These include some power purchase costs, revenue shortfall costs associated with some rate credits, and revenues from secondary power sales. These items will be covered in greater detail below.

The COSA modeling also receives input data associated with various revenue credits. Some of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by power rates. There are also revenue credits that have the effect of reducing the new resource and conservation costs. Some revenue credits that are not associated with any particular cost pool are allocated to rate pools on a pro rata load basis.

The COSA modeling concludes by using the calculated EAFs to allocate the costs and credits to the rate pools. One further adjustment to allocated costs is necessary because the costs allocated to the FPS rate pool will not be equal to the expected revenues from FPS contract sales. Therefore, an FPS surplus/deficiency adjustment to the COSA allocated costs is performed before the calculation of initial power rates. These initial power rates are the starting point for the Rate Directives Step modeling in the RAM2012.

2.1.2 Loads and Resources

The sizes of the rate and resource pools are determined based on the results of the Power Loads and Resources Study. The process of allocating power costs begins with an examination of critical period firm loads and resources. After specific adjustments are made, RAM2012 calculates a ratemaking load-resource balance for each year of the rate period. From this ratemaking load-resource balance, RAM2012 determines service to each of the four rate pools (PF, NR, IP and FPS) from each of the three resource pools (FBS, Exchange and New Resources) for the rate period.

Because the BP-12 Initial Proposal includes tiered rates, the Power Loads and Resources Study makes the distinction between PFp load to be served at a Tier 1 price and PFp load that is subject to Tier 2 pricing. The analogous distinction also holds for resources; the Power Loads and Resources Study identifies Tier 1 system resources and resources whose costs will be assigned to Tier 2 cost pools. Notwithstanding this distinction in the input data, the COSA allocations are done with the tiered loads aggregated as a single PFp load and the resources combined into the FBS. The one exception to this combining of tiered inputs is that the Base PFx rate used to establish whether a COU is eligible to participate in the REP, and therefore, the amount of exchange loads and resources in the cost allocations, does not include any Tier 2 resource costs or any Tier 2 loads in its calculation. Table 2.2.1 of the Documentation shows the ratemaking energy loads and resources by pools.

The REP, created by section 5(c) of the Northwest Power Act, was designed to provide residential and small farm customers of Pacific Northwest utilities a form of access to low-cost Federal power. Under the REP, BPA purchases power from each participating utility at that utility's ASC. BPA establishes a utility's ASC through a formal ASC Review Process. Once a utility's ASC is established, BPA offers, in exchange, to sell an equivalent amount of electric power to the utility at BPA's PFx rate. The exchange actually transfers no power to or from BPA, because the "exchange" is an accounting transaction in which dollars are exchanged, not electric power. However, to ensure proper cost allocations and rate determinations, RAM2012 models the REP as a purchase of power by BPA (priced at the participants' ASCs) and a simultaneous sale of power to the REP participant (priced at the PF Exchange rate).

2.1.2.1 Load and Resource Adjustments

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

Similarly, there is an amount of the FBS used to serve a group of power contracts that enhances the amount of FBS available to serve the ratemaking rate pools. These take the form of either a capacity-energy exchange or a seasonal exchange. Each of these types of exchanges is a "sale" of power that is paid for by returning more power than is delivered. In ratemaking, the deliveries and the equivalent returns are removed from consideration, and the energy payment is included in the FBS, increasing the size of the FBS with "free" power.

Finally, two obligations (the Southern Idaho exchange and the Sierra Pacific exchange) are transfers of power between BPA and another utility to serve BPA load in areas remote from BPA's transmission system. The BPA load that is ultimately served is included in PF loads, and retaining both the PF load and the transfer load would double-count BPA's obligation. Therefore, both the delivery of power included in loads and the receipt of an equal amount of power included in resources associated with these transfers, called locational exchanges, are removed. The ratemaking load-resource balance after adjustments is shown in Documentation, Table 2.2.2.

Load pools or rate pools are groupings of forecast sales into customer classes for cost allocation purposes. The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes sales to public body and cooperative customers (consumer-owned utilities), Federal agencies and utilities participating in the REP. The 7(c) rate pool includes sales to BPA's direct-service industrial customers under contracts authorized by section 5(d) Northwest Power Act. The 7(f) rate pool includes three groupings: (1) power sold to COUs that is determined to serve new large single loads; (2) section 5(b) requirements power sold to the region's investor-owned utilities; and (3) all power BPA sells pursuant to section 5(f) of Northwest Power Act.

The Northwest Power Act states that after July 1, 1985, BPA does not need to allocate any resource costs to the IP rate pool; rather, the IP rate is a formulaic rate established pursuant to section 7(c). However, if DSI loads were excluded from cost allocations, loads and resources would be out of balance, leaving an amount of resource costs not allocated to any loads. Therefore, BPA allocates resource costs to IP loads in common with resource cost allocations to all other remaining *(i.e.*, non-PF) firm power sold. Thus, beginning in 1985 with the implementation of the directives of section 7(c)(1)(b) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools, the 7(b) rate pool and all other loads. The resource cost allocations to the IP rate pool are adjusted later in the Rate Directives Step to conform the IP rate to its formulaic basis.

2.1.2.2 Resource Pools

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

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

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

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

2.1.2.3 Order of Resource Service to Load Pools

As noted in section 2.1.1, section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated to the Priority Firm Power customer class. That is, FBS resources are used to serve the PF rate pool until FBS resources are exhausted, whereupon exchange resources and then new resources are used to serve remaining PF rate load. Section 7(f) of the Northwest Power Act sets forth what and how costs are allocated to "all other firm power" after costs are allocated to the PF rate pool: the remaining exchange and new resources costs are allocated to remaining load. That remaining load is Industrial Firm Power, New Resources Firm Power, and Firm Power Products and Services contracts.

2.1.2.4 Allocation Factors

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

The annual EAFs for each resource cost pool as well as for the various rate directive steps are shown in Documentation, Table 2.2.3. The Total Usage and Conservation allocation factors assume a pro rata allocation of costs to all firm loads. For example, the Total Usage EAF for costs allocated to the PF load pool is equal to the ratio of PF load to total firm load. The Total

Usage and Conservation EAFs are used to allocate section 7(g) costs and rate directive allocation adjustments to all firm energy loads.

2.1.3 Ratemaking Costs

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

2.1.3.1 Revenue Requirement

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

The Power Revenue Requirement Study is based on power revenue and cost estimates for a two-year rate period, FY 2012-2013, plus the ensuing four years (for purposes of the section 7(b)(2) rate test). A preliminary generation revenue requirement from the Power Revenue Requirement Study is supplemented in the COSA for costs that are determined in other steps of the ratemaking process: projected balancing purchase power costs, system augmentation costs, PNRR, if any, and the functionalized exchange resource costs. The annual revenue requirements used for rate calculations are shown in the COSA table of Documentation, Table 2.3.2. Disaggregated costs are listed in a form consistent with the income statement from the Power Revenue Requirement Study and are shown in Documentation, Table 2.3.1. RAM2012 uses key code mapping to allocate all costs into both the COSA cost pools and the TRM cost pools. Because of the different purposes of the COSA and the TRM, the COSA cost pools are not related to the TRM cost pools; however, all costs appear in both sets of cost pools.

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

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

System Augmentation. For ratesetting purposes, it is assumed that BPA acquires resources beyond the inventory represented by the system generating resources and balancing power purchases. These system augmentation acquisition amounts are determined in the Power Loads and Resources Study and are used to meet annual customer firm power loads in excess of annual firm system resources. The forecast cost of system augmentation purchases is calculated using prices under 1937 water conditions as determined in the Power Risk and Market Price Study, BP-12-E-BPA-04. The expense estimate for system augmentation purchases is based on the application of market prices for the 50 games of the Power Risk and Market Price Study associated with 1937 water conditions. System augmentation purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. See Documentation, Tables 2.3.1 and 2.3.2.

Balancing Power Purchases. The costs of power purchases and storage required to meet firm deficits on a monthly/diurnal basis are included in the category of balancing power purchases. Projected balancing power purchases are generally needed to serve firm loads in months other than the spring fish migration period under some water conditions. The costs of balancing power purchases under 3,500 games of different risk conditions are calculated by the Risk Analysis Model (RiskMod). See Documentation, Tables 21 and 22. In the Power Risk and Market Price Study, average balancing purchase quantities are computed and valued in RiskMod against median total balancing purchase costs based upon a Monte Carlo simulation of 3,500 games. The average balancing purchase quantities and median expense dollars are combined to derive an expected balancing purchase price for balancing purchases from RiskMod. These prices and quantities are then passed to RAM2012 to compute balancing purchase costs. Balancing power purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. See Documentation, Tables 2.3.1 and 2.3.2.

2.1.3.2 Functionalization of Exchange Resource Costs

In the COSA, exchange resource costs are based on participating utilities' ASCs and their exchange power sales to BPA. ASCs include the cost of power and transmission services associated with serving a participating utility's total retail load. By definition, exchange resource sales to BPA equal the exchange sales by BPA. The rate directives adjustments that occur subsequent to the COSA use the results of the COSA allocations of the generation revenue requirement. Therefore, because the exchange resource costs in the COSA include transmission costs, the PF Exchange rate includes a transmission cost adder, and thus, the exchange resource costs are functionalized between power and transmission. The exchange resource costs functionalized to power continue through the ratemaking process. The exchange resource costs functionalized to transmission are removed from the generation revenue requirement for the Rate Directives Step and are added back to determine the PF Exchange rate after the Rate Directives

Step is completed. In this way, the exchange resource costs functionalized to power are treated the same as other power function costs through the rate development process. The transmission function costs are collected directly from PFx loads through a transmission adder included in the PFx rate. Because the amount of exchange resource costs functionalized to transmission is equal to the increased revenue due to the PF Exchange rate adder, there is no net cost of these transmission costs to other rates, and they are removed from consideration in the section 7(b)(2) rate test. The functionalization of exchange resource costs is shown in Documentation, Table 2.3.4.4.

2.1.3.3 Low Density Discount

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

The cost of providing the discount is computed in RAM2012 using offset quantities and the internally computed Customer charges. Offset quantities are the sum of the applicable LDD percentages applied to the customer-specific billing determinants. These offsets are computed in the TRM Billing Determinants Model, which is a separate module of RAM2012.

The estimated cost of the LDD is shown in Documentation, Table 2.3.3. The entire cost of the discount is allocated to the PF load pool.

2.1.3.4 Irrigation Rate Discount

A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and the TRM. The discount is a rate, expressed in mills per kilowatthour, that when applied to qualified irrigation load produces a dollar credit on eligible customer power bills. The Irrigation Rate

Discount rate is calculated in RAM2012 as described in section 3.1.11.1. The cost of the discount is computed in RAM2012 using contract irrigation loads and the internally calculated rate. The entire cost of the IRD is allocated to the PF load pool.

2.1.3.5 Cost Pools

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

2.1.3.5.1 Section 7(b)(1) costs

Section 7(b)(1) costs are associated with the resources necessary to serve PF load, including the PFp load and the PFx load. For this Initial Proposal, these resources are all of the FBS resources and a large portion of the exchange resources. Therefore, all FBS resource costs and most of the exchange resource costs are section 7(b)(1) costs allocated to serve section 7(b)(1) loads; that is, PF loads.

2.1.3.5.2 Section 7(f) Costs

Section 7(f) costs are associated with the resources necessary to serve non-PF load, including IP, NR, and FPS loads. For this Initial Proposal, these resources are a small portion of the exchange resources and all of the new resources. Therefore, a small portion of exchange resource costs and all new resource costs are section 7(f) costs allocated to serve all remaining loads; that is, IP, NR, and FPS loads.

2.1.3.5.3 Section 7(g) Costs

Conservation Costs. The Northwest Power Act requires BPA to treat cost-effective conservation savings as a resource in planning to meet the Administrator's obligations to serve loads. The "conservation" line item, as seen in Documentation, Table 2.3.1 and 2.3.2, includes (1) debt service for BPA's previous conservation resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; (3) costs associated with BPA's energy efficiency business; and (4) a share of Net Revenues (Minimum Required Net Revenues (MRNR) plus PNRR). The "Energy Efficiency" revenue line item in Documentation, Table 2.3.6, reflects payments provided by utilities, other organizations, and Federal agencies for the energy efficiency services delivered. Energy Efficiency revenues are credited against conservation costs, and the conservation costs that are net of these revenues continue through the remaining ratemaking process. See Documentation, Table 2.3.7.4. Conservation costs are allocated to all rate pools using the Conservation EAFs.

BPA Program Costs. Some of BPA's program costs are not identified directly with any specific resource pool. An example is the cost of defending legal challenges to BPA's ratemaking decisions. Development of these Power program costs occurs in the Integrated Program Review, as described in the Power Revenue Requirement Study, section 2.1. The power portion appears in the COSA as BPA program costs. BPA program costs are allocated to all rate pools based on the Total Usage EAFs. See Documentation, Table 2.3.4.5.

BPA Power Transmission Costs. Power transmission expenses include the costs of serving transfer service customers with Federal power wheeled under GTAs and other non-Federal transmission service agreements over a third-party transmission system. It also includes the costs Power Services incurs to procure transmission and ancillary services to transmit surplus Federal power to purchasers outside the Pacific Northwest. Transmission costs are allocated to all rate pools based on the Total Usage EAFs. See Documentation, Table 2.3.4.5.

2.1.3.6 Planned Net Revenues for Risk (PNRR)

PNRR is an amount of net revenues required from power rates to ensure that cash flows from proposed rates meet BPA's probability standard for repaying Power Services' portion of Treasury payments on time and in full. Under the ratemaking methodology, the amount of PNRR is the result of an iterative process between the RAM2012, RiskMod, Non-Operating Risk Model (NORM), and ToolKit models. See Power Risk and Market Price Study, section 3.3. The iteration is initiated with a seed value for PNRR in Documentation, Tables 2.3.1 and 2.3.2. The resultant rates are used in RiskMod to produce net revenue probability distributions. These net revenue distributions are then used in the ToolKit to produce a new PNRR value. See Documentation, Table 2.3.1. Because the PNRR is determined to be zero for this Initial Proposal, no iterative process is required to determine rate levels for this Initial Proposal.

2.1.4 Revenue Credits

2.1.4.1 Downstream Benefits and Pumping Power Revenues

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

2.1.4.2 Section 4(h)(10)(C) Credits

Section 4(h)(10)(C) credits are described in section 4.4.1. The forecast credit is calculated as described in the Power Risk and Market Price Study, section 2.6.1, and supplied to RAM2012. Section 4(h)(10)(C) credits are associated with FBS resources, and these credits are allocated to loads that have been allocated the costs of the FBS. See Documentation, Table 2.3.6.

2.1.4.3 FBS Contract Obligations Revenue

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

2.1.4.4 Colville Credit

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

2.1.4.5 Energy Efficiency Revenues

The Energy Efficiency revenue credit reflects revenues associated with the activities of BPA's Energy Efficiency program. These revenues are generally payments for reimbursable expenditures that are included in the generation revenue requirement. The credit is allocated as an offset to BPA's conservation expenses and reduces the amount of those expenses allocated to power rates. See Documentation, Table 2.3.6.

2.1.4.6 Miscellaneous Revenues

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

2.1.4.7 Green Tag Revenues

Green Tag revenues result from BPA's sales of Renewable Energy Certificates (RECs) supporting sales of Environmentally Preferred Power (EPP). The revenue amounts depend on actual prices and renewable project output included in the FBS and new resources resource pools. The revenues from Klondike III RECs are allocated to loads that have been allocated the costs of the FBS, and the revenues from new resources renewable resource RECs are allocated to loads that have been allocated the costs of the new resources. See Documentation, Table 2.3.6.

2.1.4.8 General Revenue Credits

Power Services, in the course of marketing power, generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing reserves and energy for ancillary services, control area services, and other reliability needs. The Generation Inputs Study explains and documents these credits. Revenues associated with Generation Inputs, Network Wind Shaping, REP benefits withheld due to outstanding deemer balance (section 2.2.3.1.3), and revenues associated with RSS for non-Federal resources are allocated to all loads through the General Cost EAFs. See Documentation, Table 2.3.7.5.

2.1.4.9 Secondary Revenue Credits

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

The ratemaking process described above ensures that the forecast of firm resources available to serve load is equal to BPA's firm load obligations under critical water conditions. However, the ratesetting process also recognizes that better than critical water conditions will most likely occur. Generation from water in excess of critical water conditions is called secondary energy. The projected secondary energy revenue credits are included so that power rates are set at a level such that revenues from all sources do not recover more than the total Power Services revenue requirement.

The sales of energy in excess of firm obligations on a monthly/diurnal basis under 3,500 games of different risk conditions are calculated by the Risk Analysis Model (RiskMod). Power Risk and Market Price Study, section 2.2.3. See Documentation, Table 2.3.8. Consistent with the Power Risk and Market Price Study, average secondary sales quantities are computed and valued against median total secondary revenues based upon a Monte Carlo simulation of 3,500 games. The average secondary sales quantities and median revenue dollars are combined to derive an expected sales price for secondary energy from RiskMod. These prices and quantities are then passed to RAM2012 to compute secondary energy revenues.

The secondary revenues projected in the RiskMod are for market sales expected to be made by BPA and do not include the portion of secondary energy that is expected to be sold to Slice customers. The ratemaking process does not consider product choice by preference customers until the Rate Design Step; therefore, the sales and revenue from RiskMod are "grossed up" to reflect the market value for all secondary energy expected to be produced by Federal generation. See Documentation, Table 2.3.8. Section 7(g) of the Northwest Power Act directs that all benefits from the sale of excess electric power not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Secondary energy revenues remaining after any allocation pursuant to section 7(b)(3), see section 2.4.1.2, are allocated to rate pools based on the FBS and new resource energy allocation factors to credit the revenues against the costs of the resources producing the secondary energy. See Documentation, Table 2.3.8.

2.1.5 Surplus Revenue Deficiency/Surplus Reallocation

BPA sells surplus firm power at prices under the FPS rate schedule. The COSA includes these sales in the FPS rate pool and allocates costs to these sales. Sales of such firm power are not necessarily made at rates that recover the exact costs allocated in the COSA to these sales.

Therefore, either a revenue surplus or a revenue deficiency will result when a comparison is made between the costs allocated to the sales of this firm power and the revenues received from the sales of such power. The expected revenue forecast from the sale of firm power, the allocated costs, and the resulting revenue deficiency for this Study are shown in Documentation, Table 2.3.9. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates. See Documentation, Table 2.3.9.

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

2.2 Rate Directives Step

The Rate Directives Step reallocates costs among load pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act—specifically sections 7(c), 7(b)(2), and 7(b)(3).

2.2.1 Description of 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.

The IP rate for sales of power to BPA's DSI customers is a formulaic 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 consists of maintaining a set relationship between the levels of the IP and PF rates for each year while simultaneously allocating costs between the two rates, and to avoid multiple iterations, the RAM2012 has an algebraic formula to approximate a solution and then uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period. See Documentation, Table 2.4.4.

After the IP-PF Link reallocation, RAM2012 conducts an IP floor rate test to determine if the currently calculated IP rate is below the IP rate that was in effect for the contract year ending on June 30, 1985, as required by section 7(c)(2) of the Northwest Power Act. The currently modeled IP rate at this point in the modeling is not below the IP floor rate, and no floor rate adjustment is needed.

With the proper relationship between the IP rate and the unbifurcated PF rate established, the Base PF Exchange rates for the IOUs and the COUs can be calculated. The Base PF Exchange rate for the IOUs is the average unbifurcated PF plus a transmission adder. The Base PF Exchange rate for the COUs begins with the IOU rate and removes Tier 2 costs and loads.

Once these steps are complete, the next step is to calculate the level of rate protection due to preference customers pursuant to section 7(b)(2) of the Northwest Power Act. The rates for this Initial Proposal are being calculated assuming that there will be a settlement of the outstanding litigation associated with the REP and the section 7(b)(2) rate test. With this in mind, and at this point in the rates modeling, a new set of REP settlement rate calculations has been added to the RAM2012. This new set of rate calculations effectively implements the section 7(b)(2) rate test through other calculations that provide preference customers with an amount of rate protection based on the express settlement amount of IOU REP benefits, any COU REP benefits for qualified REP participants, and the IP and NR rates as specified in the REP Settlement. The RAM2012 retains the ability to calculate no-REP-Settlement rates and REP benefits by using the section 7(b)(2) rate test and subsequent cost reallocations pursuant to section 7(b)(3) and 7(c)(2).

The REP Settlement rate modeling begins with total IOU REP benefits as specified in the REP Settlement agreement, Scheduled Amounts. Added to that REP benefit amount is a Lookback settlement amount, also specified in the REP Settlement agreement, known as Refund Amounts, that is included in the calculation of rates but will be credited back to preference customers in the form of a credit on their power bills. See Documentation, Table 2.4.9.

The REP Settlement rates modeling first calculates the Base Exchange Costs, which are the REP benefits that would be in place if there was no PFp rate protection. In such circumstance, the REP benefits for each exchanging utility would be its ASC minus the appropriate Base PFx rate multiplied by its qualified exchange load. The Base Exchange Costs are shown in Documentation, Table 2.4.10. These Base Exchange Costs are then used to calculate total COU REP benefits under the REP Settlement. A ratio is calculated by dividing (i) the Scheduled

Amounts plus any Refund Amounts by (ii) the total Base Exchange Costs for IOUs. This ratio is then multiplied by Base Exchange Costs for COUs to derive COU REP benefits.

The total rate protection provided to preference customers is composed of three parts. With the Base Exchange Costs and the total IOU and COU REP benefits determined, the first amount of rate protection due to preference customers is calculated as the Base Exchange Costs minus the sum of REP benefits. The cost of this first part of rate protection is allocated to the PFx rate pool. The cost of the second and third parts 0of rate protection to be allocated to the IP and NR rate pools is calculated later. The REP Settlement modeling then allocates this first amount of rate protection to individual REP participants by calculating utility-specific REP Surcharges to be added to the appropriate Base PFx rates to produce utility-specific PFx rates, which will produce the total Scheduled Amounts. See Documentation, Table 2.4.11. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are calculated and summed. A check is conducted to ensure that the sum of the calculated IOU REP benefits is the same as the total Scheduled Amounts. See Documentation, Table 2.4.12.

A second part of rate protection is calculated and allocated to the IP and NR rate pools. This second part of rate protection is equal to an REP Surcharge included in the IP and NR rates. An REP Surcharge is determined by multiplying the REP benefit costs determined above (Scheduled Amounts plus COU REP benefits) by a scalar specified in the proposed REP Settlement. This REP Surcharge, when multiplied by the expected sales under the IP and NR rate schedules, will produce an amount of dollars. A third part of rate protection is calculated and allocated to the IP and NR rate pools. This third part is calculated by subtracting the dollars calculated in the second part from the amounts of IOU and COU benefits determined above to yield a residual amount. This residual amount is allocated pro rata by load to the PFp, IP, and NR rate pools. The amount so allocated to the IP and NR rate pools is the third part of rate protection for preference customers. The dollars from the REP Surcharge and the pro rata load allocation are added to form the second part of rate protection afforded preference customers under the proposed REP Settlement.

The RAM2012 REP Settlement modeling explicitly adjusts dollars between the PFp, PFx, IP, and NR rate pools. The REP Settlement rate protection allocations have the effect of increasing the IP, NR, and PFx rates while decreasing the PFp rate. See Documentation, Table 2.4.14.

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

The REP settlement logic in the RAM2012 provides the COUs with rate protection and results in PFp, IP, and NR rates that have a similar rate level relationship to those found when the 7(b)(2) rate test is performed.

RAM2012 retains the ability to perform the Rate Directives Step ratemaking using the assumption that there is no REP Settlement. In this circumstance, the Rate Directives Step modeling is the same as with an REP Settlement, up to the point immediately following performance of the first IP-PF link. At this point in the rate modeling, the section 7(b)(2) rate test is conducted and a 7(b)(2) rate test trigger is calculated. The trigger, denominated in $/MWh, is multiplied by the PFp billing determinants to calculate an amount of PFp rate protection. That rate protection is then allocated to all other load, including surplus sales. This reallocation of rate protection dollars bifurcates the PF rate into a (lower) PFp rate and a (higher) PFx rate. The IP and NR rates are also higher after this reallocation.

The higher IP rate must then be re-linked to the now-lower PFp rate. This is accomplished with a second IP-PF Link calculation. This second IP-PF Link calculation is described in section 2.2.3.1.2. After the second IP-PF Link reallocation, the level of the PFp rate is unchanged, the level of the IP rate is lower, and the levels of the PFx and NR rates are higher.

As stated above, RAM2012 allows the user to toggle between running an REP Settlement ratemaking run and a no-REP Settlement run.

2.2.2 IP Rate

The IP rate is based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will 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." "Equitable in relation" is defined pursuant to section 7(c)(2) as basing the DSI rate on BPA's "applicable wholesale rates" to its COU customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is made through a Value of Reserves credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate, plus the typical margin, plus the VOR credit, subject to the DSI floor rate test and the outcome of the determination of PFp rate protection.

2.2.2.1 Applicable Wholesale Rate

The applicable wholesale rate is calculated as the rates at which BPA is selling power to COUs, that is, the PFp rate (for non-New Large Single Load (NLSL)) and the NR rate (for NLSLs). The IP rate begins by being set to the average of the PF and NR rates, weighted by sales to COUs at each rate, and reflecting the DSI class load factor. No sales to COUs at the NR rate are projected for this rate period.

2.2.2.2 Typical Margin, Value of Reserves, and Net Industrial Margin

A typical margin of 0.68 mills/kWh is to be added to the applicable wholesale rate. See section 3.3.1.2 and Appendix A. A VOR credit to the IP rate of 0.95 mills/kWh is calculated as described in section 3.3.1.1. The typical margin plus the VOR credit yields the "net industrial margin." The net industrial margin is added to the applicable wholesale rate, and the result is multiplied by the forecast DSI load to determine the allocated costs for the IP rate pool. See Documentation, Table 2.4.1.

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

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

2.2.2.4 IP Floor

Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers shall not be less than the rates in effect for the contract year ending June 30, 1985 (the floor rate). Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate.

If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the IP rate is set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate period (FY 2012-2013) DSI billing determinants. The resulting revenue figure is divided by total IP rate period energy loads to arrive at an average rate in mills per kilowatthour. This rate is reduced by an Exchange Cost Adjustment and a Deferral Adjustment that were included in the IP-83 rate but are no longer applicable. Both adjustments are made on a mills per kilowatthour basis.

In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total transmission costs in mills per kilowatthour from the IP-83 rate in the same manner that the Exchange Cost Adjustment and Deferral Adjustment are removed. The mills per kilowatthour component is determined by dividing total transmission costs in the IP-83 rate by the total energy billing determinants for that rate period. The transmission cost adjustment amounts to 3.81 mills/kWh. See Documentation, Table 2.4.6.

These calculations result in an undelivered IP floor rate of 20.98 mills/kWh. The floor rate is applied to the current rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed IP rates is compared to the revenue at the floor rate. Because the proposed IP rate revenue is greater than the floor rate revenue, no floor rate adjustment is necessary. See Documentation, Tables 2.4.6 and 2.4.7.

2.2.3 Section 7(b)(2) Rate Protection

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's rates for public body, cooperative, and Federal agency customers (collectively referred to as preference customers or 7(b)(2) customers) are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act.

As described in section 2.2.1 above, an REP Settlement is being considered that settles ongoing litigation regarding BPA's implementation of the rate test. The efficacy of the REP Settlement in providing adequate rate protection will be the subject of a separate section 7(i) proceeding commencing after the release of the BP-12 Initial Proposal. Pending the Administrator's decision regarding the REP Settlement, the BP-12 Initial Proposal assumes an alternative form of quantifying the rate protection afforded to preference customers. Section 2.2.3.1 describes the method to determine rate protection based on the rate test. Section 2.2.3.2 describes the method to determine rate protection based on the REP Settlement.

2.2.3.1 Section 7(b)(2) Rate Test

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's 7(b)(2) customers. The two sets of rates are (1) a set for the section 7(b)(2) rate test period (the rate period, FY 2012-2013, and the ensuing four years, FY 2014-2017) assuming that section 7(b)(2) is not in effect (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (7(b)(2) Case rates). The 7(b)(2) Case rates are modeled exactly the same as the Program Case rates except for the five assumptions listed in section 7(b)(2). The five assumptions prescribed by section 7(b)(2) of the Northwest Power Act and used to model the 7(b)(2) Case are:

(1) Within or adjacent DSI loads are transferred to public utilities at the start of the 7(b)(2) rate test period.

(2) No section 5(c) Residential Exchange Program takes place.

(3) Additional resources of three specified types serve the loads of 7(b)(2) customers when FBS resources are exhausted.

(4) The DSI reserve benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased cost to the 7(b)(2) customers.

(5) Financing benefits under provisions of the Northwest Power Act are not available in the 7(b)(2) Case. The 7(b)(2) Case rates will reflect this increased resource cost due to the absence of BPA financial backing if additional resources are required to serve 7(b)(2) customers.

If the rates produced using the section 7(b)(2) alternative assumptions are lower than the rates based on allocated costs, with one modification, the rate test is said to trigger, which means the preference customers are entitled to rate protection. The cost of this rate protection is borne by all other BPA sales, pursuant to section 7(b)(3). Because PF customers include both preference customers and REP participants, and REP participants are not entitled to rate protection, some PF customers receive rate protection, while other PF customers pay a portion of the cost of the rate protection. Thus, to allow the cost reallocations to confer the rate protection, the PF rate is bifurcated. The two resulting rates are the PF Public (PFp) rate, which receives the rate protection, and the PF Exchange (PFx) rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The cost of rate protection is collected though section 7(b)(3) Supplemental Rate Charges applied to all non-PFp sales. A further calculation is performed to determine utility-specific 7(b)(3) Supplemental Rate Charges for utilities participating in the REP.

In the non-REP Settlement case, the rate test indicates that rate protection should be afforded to preference customers, and thus the PF rate applicable to preference customers, the PFp rate, is adjusted downward. Subsequent to the section 7(b)(2) rate test, three adjustments in the Rate

Directives Step provide this rate protection to preference customers and reallocate the rate protection to other customers, as discussed in the three subsections below.

2.2.3.1.1 7(b)(3) Rate Protection Allocation

First, the PFp customer class is allocated a credit, which reduces its rate in the amount of the protection indicated by the rate test. The rate protection amount is the 7(b)(2) rate test trigger, expressed in mills per kilowatthour, multiplied by the projected PFp rate sales. This amount reduces the allocated costs for the PFp customer class. The cost of this rate protection is reallocated to all other sales. Because the rate protection is allocated, in part, to surplus power sales, the secondary revenue credit described in section 2.1.4.9 is reduced from the amount that was already credited to rates, resulting in rates that do not collect the total revenue requirement. This reduction introduces a necessary iteration to converge to an amount of secondary revenue credit that no longer changes the rate protection amount.

2.2.3.1.2 7(b)(2) Industrial Adjustment

The second step subsequent to the section 7(b)(2) rate test to provide rate protection to preference customers and reallocate the rate protection is the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. As a result of the allocation of rate protection to preference customers discussed in section 2.2.3.1.1, the PFp rate is now lower. The IP rate must then be linked to the now lower PFp rate. This is accomplished with a second IP-PF Link calculation. This second IP-PF Link calculation is different from the first IP-PF link in two ways. First, the PFp rate remains at its post-7(b)(2) rate test level, and the dollars reallocated away from the IP rate are reallocated to the PFx and NR rates. Second, the rate protection allocated to the IP rate is held aside during the linking, and this allocation is added to the IP rate after the second link. After this IP-PF Link reallocation, the level of the PFp rate is unchanged, the level of the IP rate is lower, and the levels of the PFx and NR rates are higher.

2.2.3.1.3 Deemer Balance Adjustment

The third step is the Deemer Balance Adjustment. Under Residential Purchase and Sale Agreements (RPSAs) in effect prior to the 2010 REP Settlement, a utility with an ASC lower than the PF Exchange rate was considered to be in deemer status. To eliminate the necessity for such an exchanging utility to actually pay BPA the difference between its ASC and BPA's PF Exchange rate, its ASC was deemed equal to the PF Exchange rate. The amount that would have been paid to BPA was accrued as a deemer balance. Any outstanding deemer balances must be reduced to zero before the utility is eligible to receive REP benefits.

The Deemer Balance Adjustment in ratemaking is comprised of two parts. The first part occurs when the ASC of an REP participant is less than its Base PFx rate and deeming results in an increase in exchange resource costs. Such an increase would result from the increase of the deeming utility's ASC being set equal to the higher Base PFx rate An iterative process is necessary, because as the increase in exchange resource costs is recalculated, the Base PFx rate will be affected. Because no exchanging utility is forecast to be in deemer status, this rate adjustment is not necessary.

The second part of the Deemer Balance Adjustment determines if an otherwise-eligible utility is forecast to receive REP benefits while maintaining an outstanding deemer balance. If so, the REP benefits that were otherwise due to the utility are withheld, and its deemer balance is reduced by the withheld amount. At this point in the ratemaking sequence, costs have been allocated to rate pools assuming that the utility would be receiving REP benefits. The withholding of the payment of these REP benefits would result in rates that would recover more than the total revenue requirement. Therefore, it is necessary to reflect the withheld REP benefits in the ratesetting process to demonstrate that rates will recover the lower REP benefit costs.

This reduction of REP benefit costs introduces a necessary iteration to solve the interaction between the REP benefit costs included in rates and the withheld deemer balance adjustment amount. The amount of the withheld REP benefits is credited in the COSA as a general reduction to BPA's costs. However, because this reduction in costs is specifically tied to the REP, this reduction is not reflected in the rate test in the rates reflecting the section 7(b)(2) alternative assumptions. The rate modeling iterates the actual REP benefit costs included in rates and the deemer balance adjustment.

2.2.3.2 Rate Protection Under the Proposed REP Settlement

Under the REP Settlement, rate protection is assumed to be afforded to preference customers. The amount of rate protection is calculated in the manner prescribed by the REP Settlement. In the same manner as described in section 2.2.3.1, the rate protection reduces the costs allocated to the PF rate applicable to preference customers, the PFp rate. The cost of this rate protection is reallocated to all other sales, with the exception of surplus sales. Two PF rates are the result of this reallocation—the PFp rate, which receives the rate protection, and the PFx rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The cost of rate protection is collected through REP surcharges applied to all non-PFp sales. A further calculation is performed to determine utility-specific REP surcharges for utilities participating in the REP. See Documentation, Table 2.4.11.

2.3 Rate Design Step

The Rate Design Step uses the results of the cost and credit allocations of the COSA Step, as modified by the Rate Directives Step, to develop the rate components that would recover the costs allocated to each rate pool. Three distinct rate designs are developed: (1) a tiered rate design for the PFp rate, in which the Tier 1 rates are designed using customer charges, demand,

and energy rates; (2) a traditional demand and energy design for the PFp Melded rate, the IP rate, and the NR rate; and (3) a constant annual energy rate for PFp Tier 2 rates and the PFx rate.

2.3.1 Description of Rate Design Step Modeling

Based on the results of the Rate Directives Step, RAM2012 designs rates for each rate pool. For the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied without further processing. The design of the PFp Melded rate is described in section 3.1.12. The design of the PFx rate is described in section 3.2. The design of the IP rate is described in section 3.3. The design of the NR rate is described in section 3.4.

2.3.1.1 TRM Rate Modeling

Additional processing is required before the PFp rate design can be implemented. The allocations of costs and credits performed in the COSA Step and Rate Directives Step are insufficient to inform the rate design of the PFp rate. The TRM specifies a cost allocation methodology to separate costs into the various TRM cost pools in a different manner than COSA. RAM2012 accomplishes this different cost allocation through a process of mapping disaggregated costs and credits to the TRM cost pools. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown within RAM2012, as described below.

The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, see Study section 4; and cost and credit line items internally computed in RAM2012. Internally computed line items include:

- Costs of IRD and LDD programs.
- Revenues associated with power sales to DSI customers at the IP rate.
- Revenues and costs associated with the Residential Exchange Program:

- Revenues are calculated at the PFx Rate, REP surcharges (under the REP Settlement) or 7(b)(3) Supplemental Rate Charges (under no REP Settlement). Loads are included only for customers qualifying for exchange benefits.
- Costs are calculated using the ASC and exchange load for each qualifying REP participant.

- Revenues associated with power sales at the NR rate.
- System augmentation costs required to achieve annual load-resource balance.
- Balancing power purchase costs required to serve the monthly/diurnal loads of Load Following customers.
- "Balancing" augmentation power purchases associated solely with provision of power at the Load Shaping rate on a net annual basis. (Load Shaping rate loads would equal zero on a net annual basis except that Above-RHWM loads less than one average megawatt are allowed to forgo purchasing at Tier 2 rates and have this load served at the Load Shaping rate).
- Secondary energy revenues credit.
- Revenues allocated for Unused RHWMs. See section 3.1.3.2.
- Demand and Load Shaping revenues. See sections 3.1.2.4 and 3.1.2.3.
- Cost of Network real power losses on sales to non-Slice preference customers. See section 3.1.3.1.
- Tier 2 overhead costs and other cost assignments. See section 3.1.4.1.

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

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 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. A demonstration of this equivalence is shown in Documentation, Table 2.5.5.4.

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 that are 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.

2.3.2.2 Non-Slice Cost Pool

Tier 1 costs and credits, primarily secondary revenues, that are not associated with the Slice product are allocated to the Non-Slice cost pool. The Non-Slice cost pool forms the cost basis for the Non-Slice Customer rate, which is paid by preference customers that have selected the

Load Following product or the Block product; it is also paid by customers selecting the Slice/Block product for their Block purchases.

2.3.2.3 Slice Cost Pool

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

2.3.2.4 Tier 2 Cost Pools

Costs and credits that are associated with the sale of power to serve a customer's Above-RHWM load are allocated to Tier 2 cost pools. Generally, the costs allocated to a Tier 2 cost pool are specific purchase power costs designated by BPA as being for this specific purpose. In addition to purchase power costs, Tier 2 rates are established to recover Resource Support Services, overhead, and other BPA costs that are not necessarily incurred solely for the purpose of serving Above-RHWM load, but are supportive in part of making such sales. The initial allocation of these other costs is to either the Composite cost pool or the Non-Slice cost pool. Therefore, portion of the revenues expected to be received from sales at a Tier 2 rate is reassigned to the cost pool where the initial allocation is made. See Documentation, Table 2.5.5.2.

2.4 Rate Modeling Iterations

Several iterations—both internally within RAM2012 and externally between other models and RAM2012—are required before the ratesetting process is finalized. These iterations ensure that the appropriate costs are computed and allocated consistent with the principles of the Northwest Power Act and TRM rate design.

2.4.1 Iterations Internal to the Model

2.4.1.1 Participation in the Residential Exchange Program

Participation in the REP requires that the applicable Base PFx rate is less than a participant's Average System Cost. The applicable Base PFx rate is either the Base Tier 1 PFx rate or the untiered Base PFx rate. If a utility has an ASC less than its applicable Base PFx rate, that utility is ineligible to participate in the REP. RAM2012 uses a macro loop feature to test whether, for each year of the exchange period, each utility with an ASC qualifies for the REP. If a utility does not quality, a binary index is used to exclude it, and if it does qualify, the index is set to include it. This test is done such that the exchange resource costs are calculated including the resources purchased from only REP participants, and before the Rate Directives Step of the 7(c)(2) linking of the IP and PF rates, the determination of rate protection, and subsequent reallocation of rate protection.

2.4.1.2 7(b)(3) Allocation to Surplus Sales

Although the Initial Proposal computes rates under the REP Settlement such that allocation of rate protection is not made pursuant to section 7(b)(3) in the traditional manner (see section 2.2.1), RAM2012 is capable of computing rates both as set forth in the REP Settlement and with implementation of the 7(b)(2) rate test and 7(b)(3) reallocation. Should settlement not occur, the 7(b)(3) reallocation would be applied to all non-preference loads, including secondary sales. If the 7(b)(2) rate test triggers, such that rate protection amounts are greater than zero, reallocation of the cost of rate protection to all other loads has the effect of reducing the secondary credit amount assumed in setting the Program Case and 7(b)(2) Case rates, which will change the results of the rate test. This feature of 7(b)(3) reallocation requires iteration internally in RAM2012. The costs of rate protection allocated to secondary sales reduce the dollar amount of the secondary credit. The lower credit is then reallocated in the COSA Step, and the 7(c)(2) Delta and rate test are performed again. The PFp rate changes as a result of the new rate test, and the cost of rate protection is again reallocated to all other loads. The iteration process continues until convergence, where the results of the rate test do not change the cost of rate protection allocated to all other loads, and the PFp, PFx, IP, and NR rates are stable.

2.4.1.3 Costs of Rate Discounts

The costs of the LDD and IRD (see sections 2.1.3.3 and 2.1.3.4) are mathematically related to Composite, Non-Slice, and Slice customer charges, and these charges are dependent on REP benefits and IP and NR revenues. LDD and IRD costs are indeterminate until final charges are set; however, since final charges are in part dependent upon the costs associated with these other factors, iteration in the model is necessary. As explained in sections 2.1.3.3 and 2.1.3.4, RAM2012 computes the cost of the LDD based on offset quantities and the IRD rate based on a historical percentage, which are applied to internally computed customer charges. For each iteration of the model, the appropriate charges are applied, and new discount costs are computed. These new discount costs are allocated in the COSA Step, and the Rate Directives Step and TRM Step are performed again. New charges and rates are computed, which are again applied to the discount calculations. The iterative process continues until convergence.

2.4.1.4 Contract Formula Rates

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

2.4.2 Iterations External to the Model

Some aspects of the ratesetting process are dependent upon the rates computed in RAM2012. Many of these dependencies have been integrated within RAM2012, as described above. Other dependencies are simply too large to incorporate into one model. Thus, external iterations must be performed before rates can be finalized.

2.4.2.1 Consumer-Owned Utility Average System Costs

The ASCs of COUs participating in the REP are based in part on the cost of power purchased from BPA at rates determined in RAM2012. In addition, the amount of Lookback credit that the COU will receive is also dependent upon whether the REP Settlement or the 7(b)(2) rate test is being modeled. These two factors require a recomputation of ASCs for COUs based on the PFp rate level and the Lookback credit amount. This iteration is manually performed between RAM2012 and the ASC forecast model. Revised ASCs are included in RAM2012, and rate levels are recomputed until the results converge.

2.4.2.2 Risk Analysis and Mitigation: PNRR

PNRR is an amount of net revenues required from power rates to ensure that cash flows from proposed rates meet BPA's Treasury Payment Probability (TPP) standard. The amount of PNRR is the result of an iterative process among four models: RAM2012, RiskMod, NORM, and ToolKit. See Power Risk and Market Price Study, section 3.3. The iterative process is initiated with a seed value for PNRR in revenue requirement used in RAM2012. The resultant rates are used in RiskMod and NORM to produce distributions of net revenues. These distributions are then used in the ToolKit to produce a new PNRR value for the RAM2012 revenue requirement. See Documentation, section 2. Because PNRR is determined to be zero, no iterative process is required to determine rate levels for this Initial Proposal.

In the case when an amount of PNRR is required, the PNRR value would be allocated in the same manner as any Modified Required Net Revenues (MRNR) in the revenue requirement. See section 2.1.3.6. Under the TRM rate design, PNRR is allocated entirely to the Non-Slice cost pool.

2.4.2.3 Revised Revenue Test

The revenue forecast quantifies the expected level of sales and revenue from power rates and other sources for the rate period, FY 2012-2013. Two revenue forecasts are prepared, one with current rates and the other with proposed rates. These forecasts are used to test whether current rates will recover the generation revenue requirement and, if not, whether proposed rates are sufficient to recover the generation revenue requirement. The revenue test is described in section 4 of this Study and in the Power Revenue Requirement Study, section 3.3. The power rates placed in effect October 1, 2010, are used in the calculation of revenue at current rates for FY 2012-2013, using the load forecast from the Power Loads and Resources Study.

The proposed rates as computed in RAM2012 are applied to the same loads to create a revenue forecast at proposed rates for FY 2012-2013. The revenue from this forecast is shown in Documentation, Table 4.2. These revenues are incorporated into the revenue test in the Power Revenue Requirement Study, section 4, to determine if the proposed rates are sufficient to recover the revenue requirement. If the proposed rates are not sufficient, an adjustment to the proposed rates would be required to increase the rates to a level sufficient to recover the revenue requirement.

A failed revenue test and a subsequent rate adjustment would require a manual iteration among RAM2012, the revenue forecast, and the revenue test. The form of the rate adjustment would depend on a number of factors, including the amount that the proposed rate underrecovers the revenue requirement. Generally, given the level of integration of all of the models used in the ratesetting process, the likelihood of a significant underrecovery is remote. It is more likely that an underrecovery is the result of rounding at some point in the process. An underrecovery resulting from rounding would require, at most, a minimal change to a rate.

The revised revenue test demonstrates that the proposed rates are sufficient to recover the revenue requirement, and no further rate adjustment is needed. See Power Revenue Requirement Study, section 4.

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3. RATE DESIGN

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

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

This section of the Power Rates Study describes the proposed rate design for peaking capacity use, time-of-day use, and seasonal use of power purchased from BPA under its Priority Firm Power (PF-12), Industrial Firm Power (IP-12), and New Resources Firm Power (NR-12) rate schedules.

There are three Priority Firm Power rates: the Priority Firm Public (PFp) rate, the Priority Firm Exchange (PFx) rate, and the Priority Firm Melded rate. PFp rate design is applicable to purchases by public bodies, cooperatives, and Federal agencies pursuant to Contract High Water Mark (CHWM) contracts. The PFx rate design is applicable to purchases by utilities pursuant to a Residential Purchase and Sale Agreement or the 2010 Residential Exchange Program (REP) settlement agreement. The PF Melded rate design would be applicable to purchases by public bodies, cooperatives, and Federal agencies pursuant to contracts other than a CHWM contract. There are currently no contracts with public bodies, cooperatives, and Federal agencies other than CHWM contracts; thus, no sales under the PF Melded rate are forecast during the rate period, FY 2012-2013.

The PFp rate design is based on the design set forth in the Tiered Rate Methodology (TRM), TRM-12S-A-03. The TRM established a rate design for the PFp rate schedule to be used for power sales under BPA's CHWM contracts. The rate design adopted by BPA in the TRM will not be revisited in this rate case. Only those matters the TRM left open for resolution in future rate cases are addressed in this Study.

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

The TRM did not establish a rate design for the PFx, IP, and NR rate schedules. The rate design for the IP and NR service is described in this Study, and the specific rates are set forth in the Power Rate Schedules, BP-12-E-BPA-09. Certain PFp design elements adopted in the TRM are used in the IP-12 and NR-12 rate design; in particular, the method for scaling energy rates from the market forecast and the general method for calculating the demand billing determinant.

3.1 Priority Firm Public (PFp) Rate Design

As described in the TRM, the PFp rate design includes two tiers. The tiering of the rates is a ratemaking construct that allocates the costs and credits functionalized to power; it is not an allocation of power to customers. The costs and credits functionalized to power and not allocated to the NR, IP, FPS rates are allocated to the Tier 1 and Tier 2 cost pools based upon the principle of cost causation. The forecast costs and credits allocated to Tier 1 cost pools are kept separate and distinct from those allocated to the Tier 2 cost pools. In addition to creating the Tier 1 and Tier 2 cost pools, the TRM also determined a new rate design for the Tier 1 rates.

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

Tier 2 rates coincide with the Tier 2 rate options elected by customers to meet their Above-RHWM Load obligation.

BPA is proposing two other rates, based on the TRM "component" rates. First is the PFp Tier 1 Equivalent Rate for use in contracts that have rates that benchmark to a PF HLH/LLH rate design. Second, a PFp Melded rate schedule is proposed should BPA need to serve load of a preference customer that does not have a CHWM Contract.

3.1.1 PFp Customer Cost Pools

Under the TRM, there are three Tier 1 cost pools (Composite, Non-Slice, and Slice) and the possibility of multiple Tier 2 cost pools. For the FY 2012-2013 rate period there are two Tier 2 cost pools, Load Growth and Short-Term. The method by which costs and credits are allocated among the five PFp cost pools is directed by the TRM. Costs and credits are allocated among the cost pools based on the association of the cost or credit with a product (Load Following, Block, or Slice/Block) and a tier (Tier 1 or Tier 2). The Composite cost pool includes all Tier 1 costs and credits that are not otherwise allocated to the Slice and Non-Slice cost pools. The Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Slice product. Likewise, the Non-Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Load Following and Block products (including the Block portion of the Slice/Block product). The Tier 2 Load Growth and Short-Term cost pools include all costs and credits that are attributable to the resources and services necessary for load served at a Tier 2 rate. Additional detail on these cost pools is found in section 3.1.7 below.

To calculate the Tier 1 and Tier 2 rates, all costs and credits are allocated to the appropriate cost pools; all costs functionalized to generation are allocated to one of the five PFp cost pools (Composite, Non-Slice, Slice, Tier 2 Load Growth, and Tier 2 Short-Term). As described in the COSA, section 2.1 above, the same costs and credits have also been allocated to the PF rate pool and other rate pools: IP, NR, and FPS. To account for the costs and credits allocated to these other rate pools, the revenues recoverable from the other rate pools have reduced the costs allocated to the Composite cost pool. A demonstration is included in RAM2012 that shows that the revenue requirement allocated to the PFp rate pools in the COSA equals the costs and credits allocated to the PFp cost pools after the reductions from the other rate pools. See Documentation, Table 2.5.6.1 and 2.5.6.2.

The Composite and Non-Slice cost pools contain credits for revenues collected from other components of the PFp rates. The Composite cost pool includes a credit for forecast revenue collectable from the sale of Resource Support Services. The Non-Slice cost pool includes a credit for forecast revenue collectable through the Load Shaping, Demand, and Resource Shaping charges. All of these rate design credits are necessary to ensure that the PFp rates do not overcollect the allocated revenue requirement and that the costs and credits have been properly allocated.

Once costs and rate design revenue credits have been balanced with the revenue requirement, to the extent necessary additional adjustments to the PFp cost pools are made to avoid cost shifts among products (Load Following, Block, and Slice/Block), and tiers (Tier 1 and Tier 2). These rate design adjustments move dollars from one cost pool to another through equal offsetting credits and debits and do not change the overall revenue requirement or the cost allocations among PF, IP, NR, and FPS. These rate design adjustments include three adjustments made within Tier 1 (section 3.1.3) and two adjustments made between Tier 1 and Tier 2 (section 3.1.4). The three adjustments made within Tier 1 are the Transmission Loss Adjustment, the Firm Surplus and Secondary Adjustment from Unused RHWM, and the Balancing Augmentation Adjustment. The two adjustments made between Tier 1 and Tier 2 are the Tier 2 Overhead Adjustment and the Tier 2 Balancing Adjustment. After all allocations and adjustments, $2.37 billion (average annual) is allocated to the Composite cost pool; a negative $390 million is allocated to the Non-Slice cost pool; $0 is allocated to the Slice cost pool; and $16 million is allocated to the two Tier 2 cost pools. The complete allocation of costs with all revenue credits and adjustments for the five cost pools can be found in Documentation, Table 2.3.5.

3.1.2 Rate Design Revenue Credits

3.1.2.1 Resource Support Services (RSS) Revenue Credit

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

The total annual RSS revenue credit of $2.9 million assigned to the Composite cost pool for FY 2012-2013 can be found in Documentation, Table 3.1.

3.1.2.2 Resource Shaping Charge (RSC) Revenue Credit

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

BPA committed in the TRM to apply RSS and the RSC to resources serving system augmentation needs (Klondike III) and to resources supporting the Tier 2 rates in order to make these acquisitions financially equivalent to a flat block. See TRM, section 8. In these situations, the source of the RSC revenue credit is provided either through an RSC adder to the system augmentation cost or through an RSC adder within a Tier 2 cost pool. The forecast annual RSC revenue credit of negative $189,000 for FY 2012-2013 can be found in Documentation, Table 3.1.

3.1.2.3 Load Shaping Revenue Credit

Annual revenue of $24.2 million is collected from Non-Slice customers through the Load Shaping charge and credited to the Non-Slice cost pool.

3.1.2.4 Demand Revenue Credit

Revenue of $56.4 million is collected from Non-Slice customers through the Demand charge and credited to the Non-Slice cost pool.

3.1.3 Rate Design Adjustments Made between Tier 1 Cost Pools

3.1.3.1 Transmission Loss Adjustments

The Transmission Loss Adjustments provide a credit to the Composite cost pool and an equivalent debit to the Non-Slice cost pool based on Non-Slice transmission losses. The Transmission Loss Adjustments account for different accounting of transmission losses to the Slice/Block and non-Slice products. The non-Slice products and the Block portion of the Slice/Block products are delivered to the purchaser's load service area. The cost of generating the real power losses for the transmission of non-Slice sales is included in BPA's revenue requirement. Conversely, the cost of generating the real power losses for the transmission of Slice sales is borne by the purchaser. The Transmission Loss Adjustments transfer the cost of generating the real power losses for the transmission of non-Slice sales from the Composite cost pool to the Non-Slice cost pool. The Transmission Loss Adjustments are calculated by multiplying the network losses associated with the Non-Slice products, including the Block portion of the Slice/Block product, by the average Tier 1 PF Equivalent Rate (see Documentation, Table 2.5.7.1). Losses associated with the Non-Slice products are 1.9 percent of non-Slice Tier 1 sales. The calculation and result of the Transmission Loss Adjustments can be found in Documentation, Table 2.5.3.

3.1.3.2 Firm Surplus and Secondary Adjustments from Unused RHWM

Unused RHWM occurs when a customer's Forecast Net Requirement is less than its RHWM (or, for this Initial Proposal, its Proxy RHWM). The Firm Surplus and Secondary Adjustments from Unused RHWM reallocate costs between the Composite cost pool and the Non-Slice cost pool.

Unused RHWM reduces the need for system augmentation and/or increases firm power available for sale in the market. The reduced augmentation expenses and/or increased firm power market revenues are reflected in three lines on the TRM cost table: Augmentation Power Purchases; and the two Firm Surplus and Secondary Adjustments (from Unused RHWM). See Documentation, Table 2.5.1. The Augmentation Power Purchases line is part of the Composite cost pool. Both the Composite and Non-Slice cost pools contain a Firm Surplus and Secondary Adjustment (from Unused RHWM), with one reflecting a credit and the other an equal and offsetting debit.

The Firm Surplus and Secondary Adjustments have two purposes. One purpose is to reflect the difference between the value of a flat annual block of system augmentation and the value of the Unused RHWM when the Unused RHWM displaces augmentation. The difference between a flat annual block of system augmentation and the shape of the Unused RHWM is reflected in changes in the assumed balancing purchases and associated costs. These changes in balancing purchase costs are captured in the Non-Slice cost pool. A Firm Surplus and Secondary Adjustment reallocates this change in balancing purchase costs associated with this difference in value from the Non-Slice cost pool to the Composite cost pool.

The second purpose of the Firm Surplus and Secondary Adjustments is to reflect the full value of the Unused RHWM when the Unused RHWM creates firm surplus power. The revenue associated with this change in firm surplus power related to the Unused RHWM is reflected in the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary

Adjustment reallocates this change in secondary revenues associated with the Unused RHWM from the Non-Slice cost pool to the Composite cost pool.

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

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

3.1.3.3 Balancing Augmentation Load Adjustments

Balancing augmentation load is Above-RHWM load that will be served at Load Shaping rates, rather than at Tier 2 rates or with a non-Federal resource. Above-RHWM load is served at load shaping rates either when a Load Following customer's annual Above-RHWM load is less than 8,760 MWh and the Load Following customer made no alternative election to serve its Above-RHWM load, or when Above-RHWM load is locked down and the load forecast is updated during the rate case to reflect the forecast of a larger load. When the amount of system augmentation purchases is equal to or greater than the amount of balancing augmentation load, the acquisition costs attributable to supplying balancing augmentation load are included as a system augmentation expense in the Composite cost pool. The revenue from supplying balancing augmentation load is credited to the Non-Slice cost pool through the Load Shaping charge revenue credit. Without a Balancing Augmentation Load Adjustment, only Non-Slice customers would receive a credit through an increased Load Shaping Charge revenue credit, but both Slice and Non-Slice customers would bear the cost of an increased system augmentation expense. The Balancing Augmentation Load Adjustment corrects this inequity with a credit to the Composite cost pool and an equal debit to the Non-Slice cost pool.

The Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the lesser of the sum of Above-RHWM loads served at Load Shaping rates for each fiscal year or the augmentation amount for each fiscal year, the result multiplied by the augmentation price for the respective fiscal year. The Balancing Augmentation Adjustment line item in the Composite cost pool is a credit, and the Balancing Augmentation Adjustment line item in the Non-Slice cost pool is an equal and offsetting debit.

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

3.1.4.1 Tier 2 Overhead Adjustment

The Tier 2 Overhead Adjustment credits the Composite cost pool for the overhead costs charged to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost Adder, which reflects a proportionate share of BPA's total overhead costs (see section 3.1.7.1). The Tier 2 Overhead Adjustment credited to the Composite cost pool is equal to the sum of the Overhead Cost Adders charged to all of the Tier 2 cost pools. This Tier 2 Overhead Adjustment for FY 2012-2013 can be found in Documentation, Table 3.2.

3.1.4.2 Tier 2 Balancing Adjustments

Purchases to serve Above-RHWM load are made in whole average megawatts. Tier 2 purchase amounts are calculated in average kilowatts. This results in a fractional megawatt surplus in the

FY 2012 Short-Term rate pool and fractional megawatt deficits in the FY 2013 Short-Term and Load Growth rate pools. The Tier 2 Balancing Revenue Adjustment credits or debits a Tier 2 cost pool when the power purchases do not exactly equal the sales at the Tier 2 rate.

When Tier 2 purchases exceed (or are less than) Tier 2 load obligations (Tier 2 imbalance), a credit (or debit) is applied to the applicable Tier 2 cost pool, and an equal and offsetting debit (or credit) is applied to the Composite cost pool, the Non-Slice cost pool, or a combination of the Composite and Non-Slice cost pools. The respective credits and debits are calculated by multiplying either the annual augmentation price or the flat annual equivalent of the AURORA market price forecast for each fiscal year (see Power Risk and Market Price Study Documentation, Table 17) by the difference between sales at the Tier 2 rate and the megawatthours purchased to meet that load. The augmentation price is used in the calculation when the Tier 2 imbalance changes the amount of augmentation expense included in the Composite cost pool. Conversely, the AURORA market price is used when the Tier 2 imbalance changes the amount of firm surplus in the Non-Slice cost pool. See Documentation, Table 3.3, for the flat annual equivalent of the AURORA market price forecast, the annual augmentation price, and the annual augmentation amount. Both the Composite and Non-Slice cost pools can be credited or debited if there is a Tier 2 imbalance and the total amount of augmentation is less than the Tier 2 imbalance.

In the Initial Proposal, the Tier 2 Balancing Adjustment impacts only the augmentation amount and not the firm surplus amount. Therefore, only the annual augmentation price was used to calculate the Tier 2 Balancing Adjustment. See Documentation, Table 3.2, for the result of this calculation.

3.1.5 PFp Tier 1 Billing Determinants

3.1.5.1 Tier 1 Cost Allocator

The majority of BPA's costs to be collected through PF rates are allocated among customers through the Tier 1 Cost Allocator (TOCA). The TOCA is the customer-specific billing determinant used to collect the costs allocated to the Composite cost pool. A TOCA is calculated for each fiscal year of the rate period for each PFp customer. Each customer's annual TOCA is calculated as a percentage by dividing the lesser of an individual customer's RHWM or its Forecast Net Requirement by the total of the RHWMs for all PFp customers. The Initial Proposal uses Proxy RHWMs for the calculation of the TOCAs for FY 2012-2013. See section 1.6.1 for further explanation of the Proxy RHWM calculation. The TOCA is a percentage rounded to 5 decimal places.

The Forecast Net Requirement and RHWM for the individual customer and the sum of RHWMs for all customers are expressed in average annual megawatts and rounded to three decimal places. The total of the Proxy RHWMs for all customers can be found in Table 1, and the forecast sum of TOCAs used for FY 2012-2013 can be found in Documentation, Table 2.5.5.3.

3.1.5.2 Non-Slice TOCA

The Non-Slice TOCA is the billing determinant that is used to collect the costs allocated to the Non-Slice cost pool. A Non-Slice TOCA is calculated for each PFp customer for each year of the rate period. The Non-Slice TOCA is equal to a customer's TOCA if the customer is purchasing the Load Following or Block product. The Non-Slice TOCA for customers purchasing the Slice/Block product is computed as the difference between the customer's TOCA and its Slice Percentage. The Non-Slice TOCA percentage is rounded to 5 decimal places. The forecast sum of Non-Slice TOCAs used for FY 2012-2013 can be found in Documentation, Table 2.5.5.3.

3.1.5.3 Slice Percentage

The Slice Percentage is the billing determinant used to collect the costs allocated to the Slice cost pool. A Slice Percentage is calculated for each year of the rate period for PFp customers purchasing the Slice/Block product. The Slice Percentage in Exhibit K of Slice customers' CHWM contract is updated each year. The Slice Percentage can be adjusted, pursuant to section 3.6 of the TRM. The Slice Percentage is rounded to 5 decimal places.

3.1.5.4 Load Shaping Billing Determinant

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

A customer's System Shaped Load is calculated as the RHWM Tier 1 System Capability (see section 1.6.2) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the customer's Non-Slice TOCA. The Load Shaping billing determinants are calculated as the amount of a customer's monthly/diurnal electric load (measured in kilowatthours) to be served at Tier 1 rates less the customer's System Shaped Load for the same monthly/diurnal period.

Monthly/Diurnal RHWM Tier 1 System Capability. The TRM specifies that the monthly/diurnal shape of the RHWM Tier 1 System Capability will be used to compute the System Shape Load for purposes of computing Load Shaping billing determinants. This shape is computed to be constant across both years of the rate period and is the average of each year's respective monthly/diurnal megawatthour amount. In a rate period that does not include a leap year, there will be 24 monthly/diurnal amounts for the RHWM Tier 1 System Capability specified in the GRSPs. In a rate period that includes a leap year, there will be 26 amounts, because each February has a unique value for each HLH and LLH period. See GRSPs, section II.Q.

3.1.5.5 Demand Billing Determinant

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

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

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

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

Twelve CDQs are specified for each PFp customer in the customers' CHWM contract.

For the Initial Proposal, CDQs are not yet available; to allow rates to be determined, a Proxy CDQ has been estimated by using 6 months of adjusted Measured FY 2010 Loads and 6 months of adjusted Measured FY 2008 Loads. Measured FY 2010 Loads are in monthly amounts. The HLH energy is estimated by applying each customer's respective actual Total Retail Load HLH and LLH split.

The Super Peak Credit will be determined pursuant to a customer's CHWM contract. The Super Peak Period hours for FY 2012-2013 are defined in the GRSPs as follows (HE = Hour Ending):

October - February	HE 8 through HE 10 and HE 18 through HE 20
March - May	HE 7 through HE 12
June - September	HE 14 through HE 19

3.1.6 PFp Tier 1 Rates

3.1.6.1 Tier 1 Customer Rates

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

The monthly rates for each of the Tier 1 cost pools are shown Documentation, Table 2.5.5.3.

3.1.6.2 Tier 1 Load Shaping Rates

The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—for each of 12 months). The Load Shaping rates are set equal to the rate period average marginal cost of power for each monthly/diurnal period as determined in the Power Risk and Market Price Study, section 2.4. Also see Documentation, Table 3.4.

3.1.6.2.1 Load Shaping True-Up

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

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

This special implementation provision is designed to solve a transitional implementation issue caused by setting Above-RHWM load based on a different forecast than is used to determine a customer's TOCA. This implementation provision is necessary in this rate period because Above-RHWM Load was determined in 2009 and the calculation of a customer's TOCA will be in 2011. A consequence of using forecasts prepared at different times is the possibility that a customer has both Above-RHWM Load and unused RHWM. This cannot happen if the same forecast is used to set both Above-RHWM Load and customers' TOCAs.

First, if the Annual Deviation calculation of the Load Shaping Charge True-up is negative or equal to zero and the absolute value of AnnualDeviation is less than the customer's Above-RHWM Load, then the additional credit is equal to the Load Shaping True-up rate multiplied by (1) the customer's Above-RHWM load, or (2) the Above-RHWM load less the absolute value of the AnnualDeviation amount, or (3) the AboveForecast amount, whichever is the smallest. Second, if the AnnualDeviation calculation of the Load Shaping Charge True-up is positive and the AnnualDeviation amount is less than the AboveForecast amount, then the additional credit is equal to the Load Shaping True-up rate multiplied by the lesser of (1) the customer's Above-RHWM load or (2) the AboveForecast amount less the AnnualDeviation amount.

3.1.6.3 Tier 1 Demand Rates

The Demand rate is based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS-100 combustion turbine, as determined by the Northwest Power and Conservation Council's Microfin model used in the Council's Sixth Power Plan. The Microfin model is used to obtain an estimate for the all-in capital costs in 2012 dollars of a publicly owned LMS-100 with a 2012 in-service date. The all-in capital cost under these specifications is $1,083/kW. See Documentation, Table 3.5.

The projected debt payment on the $1,083/kW fixed capital costs is estimated at $114.84/kW/yr, based on a cost of debt of 4.71 percent financed over 30 years. The cost of debt is estimated with BPA's FY 2012 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. See FY 2010 Common Agency Assumptions memo in the Power Revenue Requirement Documentation, chapter 6.

The cost of fixed O&M included in the demand rate calculation is obtained from the California Energy Commission's (CEC) Comparative Costs of California Central Station Electricity Generation report, CEC-200-2009-07SF. The calculation of the demand rate uses the CEC's average 2009 estimate and is escalated to 2012 and 2013 dollars using the 2004 to 2009 average (5-year) rate of 2.52 percent calculated from the Implicit Price Deflators from the U.S. Bureau of Economic Analysis. The two-year average annual cost for fixed O&M is $17.82/kW.

Insurance and fixed fuel are also included in the calculation of the demand rate. The annual insurance cost of $2.62/kW is calculated based on 0.25 percent of the mid-year assessed value obtained from the Council's Microfin model 14.2.11. The fixed fuel cost assumed in the demand rate calculation is $26.26/kW/yr. The fixed fuel cost is estimated using a heat rate of 8,770 Btu/kWh, Williams Northwest Pipeline Tariff of $0.37984/MMBtu/day, and an offsetting revenue credit equal to 10 percent for the resale of firm pipeline rights. See Documentation, Table 3.6.

The average annual expense is $114.95/kW. This annual value is shaped into the 12 months of the year using the Load Shaping rates. See Documentation, Table 3.5.

3.1.6.4 PFp Tier 1 Equivalent Rates

The PFp Tier 1 Equivalent rates consist of 12 HLH and 12 LLH energy rates and 12 demand rates. The PFp Tier 1 Equivalent energy rates are equal to the Load Shaping rates less a single $/MWh value. The demand rates are equal to the Tier 1 Demand rates. The single $/MWh value scales the Load Shaping rates to a level at which the PFp Tier 1 Equivalent energy rates, in conjunction with the demand revenue, would collect the Tier 1 revenue requirement allocated to the PFp non-Slice loads (the Composite cost pool plus the Non-Slice cost pool). This single

$/MWh value is equivalent to the Load Shaping True-Up rate. This calculation can be found in Documentation, Table 2.5.7.1.

3.1.7 PFp Tier 2 Cost Pool

There are two Tier 2 rates—the Short-Term rate and the Load Growth rate. Costs allocated to the aggregate Tier 2 cost pool are further allocated to the Short-Term and the Load Growth cost pools. For the rate period, those costs are the actual costs associated with the flat-block energy purchases at the transacted amounts and prices. Costs for Tier 2 Overhead Adjustment, Tier 2 Balancing Adjustment, and scheduling services are added to these cost pools and are described below in the following sections.

3.1.7.1 Tier 2 Overhead Cost Adder

Section 6.3.3 of the TRM describes an Overhead Cost Adder to be included as part of the Tier 2 rates. The overhead cost components used to calculate the Tier 2 Rate Overhead Cost Adder are listed in Table 3.7 of Documentation. The rate period total of these overhead costs is divided by BPA's total forecast of revenue-producing (PFp, IP, NR, FPS, Downstream Benefits and Pumping Power, Pre-subscription, Generation Inputs for Ancillary and Other Services Revenue, and Secondary sales) energy sales, which results in $1.17/MWh adder for the rate period. The $/MWh value in each year is multiplied by the amount of planned sales in each year for each Tier 2 alternative (Short-Term and Load Growth) to produce a dollar value for the Overhead Cost Adder included in each cost pool for each year. The Tier 2 Overhead Cost Adder provides the revenue credit to the Composite cost pool (called Tier 2 Overhead Adjustment); see section 3.1.4.1 above. The specific cost and sales values used in these calculations can be found in Documentation, Table 3.2.

3.1.7.2 Tier 2 Transmission Scheduling Service Cost Adder

A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS Adder is calculated by dividing the Operations Scheduling costs for the rate period by the total megawatthours actually scheduled in FY 2009 and FY 2010 to produce a yearly $/MWh value. The TSS Cost Adder is $0.20 mills/MWh. This calculation is summarized in Table 3.3 of the Documentation. Inputs to this calculation are also included in Documentation, Table 3.8. This value is multiplied by the amount of planned Tier 2 sales in each year for each Tier 2 alternative (Short-Term and Load Growth) to produce the annual cost value for the TSS Cost Adder included in each cost pool for each year. The Tier 2 TSS Cost Adder is one of the credits to the Composite cost pool summed in the Resource Support Services Revenue Credit; see section 3.1.2.1 above. The calculated costs assigned to each cost pool in each year can be found in Documentation, Tables 3.9 and 3.10.

3.1.7.3 Tier 2 BPA Market Purchases

BPA made a total of three purchases for Tier 2 rate service in the FY 2012-2013 rate period. The power amounts are roughly equal to the Tier 2 load obligation for each year plus the real power losses required to deliver the power to the purchasers. Purchase costs for FY 2012 are allocated entirely to the Short-Term cost pool. Purchase costs for FY 2013 are allocated on a pro rata load basis between the two Tier 2 cost pools for FY 2013. The average megawatt amounts and their associated power purchase prices are summarized in Documentation, Table 3.11.

3.1.7.4 Tier 2 Risk Analysis

The risk analysis for Tier 2 rate service is addressed in the Power Risk and Market Price Study, section 4.3. Consistent with that discussion, no risk mitigation treatment is added to these cost pools to cover risks in the FY 2012-2013 rate period.

3.1.8 PFp Tier 2 Billing Determinants

The Tier 2 billing determinant is equal to each customer's commitment to purchase from BPA all or a portion of its Above-RHWM load. Each customer's Tier 2 rate service amount is contractually established for FY 2012-2013, as summarized in Table 3.12 of the Documentation. Because there are no purchases of Load Growth service in FY 2012, no costs are allocated to the Load Growth cost pool for FY 2012.

3.1.9 Tier 2 Rates

Based on the annual average megawatt load obligations for each Tier 2 rate alternative (Short-Term and Load Growth) in each year and the costs for each cost pool in each year, Tier 2 rates are calculated as summarized in Tables 3.9 and 3.10 of Documentation. Each rate is calculated by dividing the annual costs allocated to the specific Tier 2 cost pool by the billing determinants in that same fiscal year. A specific Tier 2 rate in each year for each Tier 2 rate alternative is necessary because there are different sets of customers associated with each rate, different costs from the separate purchases, different allocations to Tier 2 cost pools, and different surplus/deficit calculations (Tier 2 Balancing Adjustment).

3.1.9.1 Tier 2 Rate TCMS Adjustment

The Tier 2 rate schedule will include an adjustment for TCMS-related costs, if a transmission event (in the form of either a planned transmission outage or a transmission curtailment) has occurred along the transmission path between Mid-C and the BPA Power Services point of receipt for the market purchases allocated to the Tier 2 cost pools. The adjustment is described in GRSPs Section II.S.

3.1.10 Calculating Charges to Reduce Tier 2 Purchase Amounts

Section 2.4.2 of Exhibit C of the Load Following CHWM contract provides customers with an opportunity to reduce the purchase amounts supplied by BPA at the Tier 2 Short-Term rate, if notice is provided by October 31 of a Rate Case Year, which is October 31, 2010, for the BP-12 rate case. If a customer makes this election, BPA may levy charges to cover costs that BPA is obligated to pay and is not able recover through other transactions. Section 2.4.2.1 of the contract states that BPA shall determine the costs, if any, to be collected from such charges during the 7(i) Process following a customer's notice to reduce its Tier 2 rate purchase amount. Two customers elected to reduce their Short-Term rate purchase amounts for the FY 2012-2013 period, and one customer elected to reduce its Short-Term rate purchase amounts in FY 2013. This amounted to 0.166 aMW of total reduced service in FY 2012 and 0.792 aMW in FY 2013. The notices were provided prior to BPA making any purchases to meet its Short-Term rate load obligations, so BPA has not incurred any costs due to these purchase reductions, and therefore there are no costs that need to be recovered through such charges.

3.1.11 PFp Irrigation Rate Discount

The Irrigation Rate Discount (IRD) is a discount to the PFp Tier 1 rates for eligible irrigation load served by a customer. The discount will appear as a credit on customer bills as an offset to the charge of eligible irrigation load at Tier 1 rates. This discount is available to eligible loads during May, June, July, August, and September during the BP-12 rate period. See GRSPs section II.H.

3.1.11.1 Irrigation Rate Discount Rate

The TRM establishes the method for calculating the IRD rate. The process begins with a fixed IRMP percentage equal to one minus the ratio of (1) the sum of the Irrigation Rate Mitigation Program (IRMP) participants' estimated charges at the FPS rates paid under IRMP for FY 2009 to (2) the sum of the IRMP participants' estimated charges that would have occurred under May through August HLH and LLH PF-07 energy rates for FY 2009 adjusted for any applicable discounts such as the LDD. See TRM, TRM-12S-A-03 at 93. The IRMP percentage so calculated is 37.47 percent. See Documentation, Table 2.3.3.

The IRD ratesetting process continues by dividing the sum of the costs allocated to the Composite and Non-Slice cost pools by the Tier 1 System Capability (expressed in megawatthours). This quotient is then multiplied by the fixed percentage to derive a dollars per megawatthour discount. The result is $12.15/MWh. The calculation is shown on Table 2.3.3 of Documentation.

3.1.11.2 Irrigation Rate Discount Bill Credit

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

3.1.11.3 Irrigation Rate Discount True-up

At the end of each irrigation season, customers with eligible irrigation load will send to BPA their measured May through September irrigation load amounts. If BPA determines that the measured irrigation load amounts are less than the eligible irrigation load amounts set forth in Exhibit D of the customer's CHWM contract, then the purchaser shall reimburse to BPA excess IRD credits. Excess IRD credits will be calculated as the IRD rate multiplied by the difference between the contract irrigation load and the measured irrigation load. See GRSP section II H.2.

3.1.12 PFp Melded Rates (Non-Tiered Rate)

Melded PF Public rates are included in the PF rate schedule. The PFp Melded rates consists of 12 HLH and 12 LLH energy rates and 12 demand rates. The PFp Melded energy rates are equal to the Load Shaping rates less a single dollar per megawatthour value. The applicable Demand rates are equal to the PFp Tier 1 Demand rates. The single dollar per megawatthour value adjusts the Load Shaping Rates so that the PFp Melded energy rates, in conjunction with the demand revenue, do not collect more or less revenues than the Tier 1 and Tier 2 revenue requirement allocated to the PFp Non-Slice loads. This single dollar per megawatthour value is the PFp Melded Equivalent Energy Scalar, which is also used in the Slice True-up to determine the actual DSI revenue credit. This calculation is shown in Documentation, Table 2.5.7.2.

The PFp Melded energy rates are used to shape and set the level of the IP energy rates, as described in section 3.3.1.

3.1.13 PFp Resource Support Services (RSS)

BPA offered customers access to Resource Support Services (RSS) and related services for their variable, non-dispatchable non-Federal resources, in accordance with the CHWM contract. The related services include Transmission Scheduling Service (TSS) and Transmission Curtailment Management Service (TCMS). In general, these services are designed to financially convert a variable, non-dispatchable resource into a flat annual block of power or the specified monthly/diurnal resource shape found in Exhibit A of the customer's CHWM Contract.

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

Costs for RSS are not allocated to the Tier 2 cost pools in this rate period because there are no variable, non-dispatchable resources assigned to the Tier 2 cost pools. Costs for TSS are allocated to the Tier 2 cost pools, and the method for doing so is described above in section 3.1.7.2. Costs for TCMS events associated with Tier 2 rate service are recovered through a mechanism known as the Tier 2 Rate TCMS Adjustment, described above in section 3.1.9.1.

3.1.13.1 RSS Rates

RSS rates are included in both the PF rate schedule and the FPS rate schedule. The rates described here under the PFp section include Diurnal Flattening Service energy and capacity rates, Resource Shaping rates and adjustment, Secondary Crediting Service shortfall and secondary energy rates, and Secondary Crediting Service Administrative Fee rate. The rates described under the FPS section below include Forced Outage Reserve Service energy and capacity rates, TSS rate, and TCMS rate. In total, about $3 million of forecast RSS and TSS-related revenue credits are applied to the Tier 1 cost pools. See Documentation, Tables 3.1 and 3.2.

3.1.13.2 RSS Diurnal Flattening Service, Resource Shaping Charge, and Resource Shaping Charge Adjustment

3.1.13.2.1 Diurnal Flattening Service (DFS)

DFS is an optional service that financially converts the output of a variable, non-dispatchable resource into one that is equivalent to a flat amount of power, within each diurnal period of a month. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. BPA selected a flat annual block of power as the benchmark shape to which to compare new non-Federal resources and Tier 2 purchases.

The RSS module of RAM calculates a unique set of rates and charges for each resource to which DFS is applied. Illustrative model runs for example resources are included in the Documentation to show how the various charges and rates would be calculated for a sample resource. See Documentation, Tables 3.13 – 3.20. Also included in the Documentation are the Initial Proposal rates and charges calculated for the customers that have requested DFS for their resources. See Documentation, Table 3.21. The PF-12 rate schedule includes a section on the general rate application of the DFS-related charges. See PF-12 Rate Schedule, section 5.1. The GRSPs include the calculations for the DFS capacity charges, DFS energy charges, and Resource Shaping charges for the resources to which DFS is applied. See GRSPs, section II.P.

Briefly, DFS charges include the following elements:

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

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

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

3.1.13.2.2 DFS Capacity Charge

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

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

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

Monthly Firm Capacity. The RSS module of RAM calculates monthly firm capacity amounts for each resource. This calculation represents the lowest level of historical generation in a HLH period for each month, after accounting for planned and forced outages. Because planned outages are not included in the FY 2009 data, a planned outage adjustment is not necessary. Therefore, the firm capacity of a resource is calculated as the percentile equal to the forced outage rating calculated from the historical monthly HLH generation levels. In other words, a resource with a 5 percent forced outage rating would have a firm capacity amount equal to the 5th percentile of the hourly historical generation amounts for the HLH period of a month.

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

DFS Capacity Charge. For each resource, the DFS capacity charge is the lesser of:

(1) the sum of (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants

or

(2) the annual average Exhibit D amount multiplied by the sum of the monthly PF Tier 1 Demand rates

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM contract. See Documentation, Tables 3.16 and 3.15, for an example of application of both the default DFS capacity charge and a DFS capacity charge that has been capped by the annual test. Table 3.21 of Documentation has the individual DFS capacity charges that are calculated for the individual resources to which DFS is applied.

3.1.13.2.3 DFS Energy Charge

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

DFS Energy Billing Determinant. The DFS energy billing determinant is the total actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. For wind resources within the BPA Balancing Authority Area, transmission curtailments associated with Dispatcher Standing Order (DSO) 216 will be treated as lowered scheduled amounts when calculating the actual generation for such a resource.

DFS Energy Charge. The DFS energy charge is the product of multiplying the DFS energy rate by the DFS energy billing determinant for each month. Table 3.21 of the Documentation shows the DFS energy rates that are calculated for the individual resources to which DFS is applied. Section II.P.1.(b) of the GRSPs includes the formula for calculating the DFS energy charges for the individual resources to which DFS is applied.

3.1.13.2.4 Resource Shaping Charge

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

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

Resource Shaping Charge. For each resource, the Resource Shaping charge is the product of multiplying the Resource Shaping rate by the Resource Shaping billing determinant. The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge. On a monthly basis this calculation can result in a charge or a credit.

The flat monthly Resource Shaping charge that results from this calculation will be reflected on the customer's monthly bill. Example calculations for a wind resource and a solar resource are included in the Documentation, Tables 3.16 and 3.18. Table 3.21 of the Documentation shows the Resource Shaping charges that are calculated for the individual resources to which DFS is applied. Section II.P.1.(c) of the GRSPs includes the formula for calculating the Resource Shaping charges for the individual resources to which DFS is applied.

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

3.1.13.2.5 Resource Shaping Charge Adjustment

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

Resource Shaping Charge Adjustment Billing Determinant. For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from CHWM contract Exhibit D amounts and the actual monthly/diurnal generation of the resource. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and Unauthorized Increases in the determination of actual generation. For wind resources within the BPA Balancing Authority Area, transmission curtailments associated with DSO-216 will be treated as lowered scheduled amounts when calculating the actual generation for such a resource.

Resource Shaping Charge Adjustment. For each resource, the Resource Shaping Charge Adjustment is the product of multiplying the Resource Shaping rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. The purpose of this charge is to capture the cost or value of the energy differences between the Exhibit D amounts and the actual generation of the resource. This adjustment completes the financial conversion to a flat annual block of power by making up for any energy cost differences between planned and actual generation amounts. On a monthly/diurnal basis this calculation can result in either a charge or a credit. Section II.P.1.(d) of the GRSPs includes the formula for calculating the Resource Shaping Charge Adjustment for the individual resources to which DFS is applied.

3.1.13.2.6 DFS and Resource Shaping Charge Application to Tier 1 Augmentation

The TRM states that RSS pricing will be used to make certain Federal resource acquisitions financially equivalent to a flat block. TRM, section 8. In addition, Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. TRM, section 3.5. The costs of Klondike III, a wind resource, are allocated to Tier 1 Augmentation. The RSS module of RAM calculates a DFS Capacity charge, DFS Energy charge, and Resource Shaping charge for Klondike III. The billing determinant for the DFS Energy charge is the planned generation amount based on the historical generation year data, in lieu of actual generation data. In addition, the RSS module calculates a TSS charge for Klondike III. The sum of the charges for Klondike III for each year is allocated to the Tier 1 Composite cost pool under the "Augmentation RSS and RSC Adder" line item. There is no Resource Shaping Charge Adjustment applied to Klondike III. Table 3.21 of Documentation shows the summary DFS, Resource Shaping, and TSS charges that are calculated for Klondike III.

3.1.13.3 RSS Secondary Crediting Service (SCS)

SCS provides a credit to a Load Following customer that dedicates to its load the entire output of a hydroelectric Existing Resource for the energy produced by that resource that is in excess of the monthly/diurnal amounts specified in the CHWM Contract Exhibit A or a charge for any energy shortfall by the resource from the monthly/diurnal Exhibit A amounts. If a customer does not take this service, it must apply the exact Exhibit A amounts to its load.

Credits are provided to the customer when its resource generates more than the contract amount. This additional generation would increase BPA's revenues because of the increased secondary energy BPA can market or would lower BPA's costs because of reduced balancing purchases. Likewise, when generation is less than the contract amounts, the customer is charged, because BPA's secondary revenues would be lower or BPA's balancing costs would be higher. The unanticipated credit or cost BPA would experience is passed through to the customer by the SCS, using the posted Resource Shaping rate as the market rate. The PF-12 rate schedule includes a section on the rate application of the SCS-related charges. The GRSPs include the formulas for calculating the SCS charges for the resources to which SCS is applied. GRSPs, section II.P.2. Table 3.21 of Documentation includes the individual SCS Administrative Charges for the individual non-Federal resources to which SCS is applied.

3.1.13.3.1 SCS Pricing Summary

The charges and credits for SCS are intended to reflect the cost or value of reshaping the customer's resource into its Exhibit A amounts.

The SCS charges include the following elements:

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

3.1.13.3.2 SCS Shortfall Energy Charges and Secondary Energy Credits

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

SCS Billing Determinant. For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and the monthly/diurnal generation from Exhibit A amounts. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

SCS Shortfall Energy Charge/Secondary Energy Credit. For each resource, the charge or credit is the product of multiplying the SCS Energy rate by the SCS Energy billing determinant for each monthly/diurnal period. If the actual generation exceeds the Exhibit A amount, the customer will receive a credit. If the actual generation is less than the Exhibit A amount, the customer will receive a charge. Section II.P.2.(a) of the GRSPs has the formula for calculating the SCS Shortfall Energy Charges/Secondary Energy Credits for the individual resources to which SCS is applied.

3.1.13.3.3 SCS Administrative Charge

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

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

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

SCS Administrative Charge. For each resource, the SCS Administrative charge is the product of multiplying the SCS Administrative rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The flat monthly SCS Administrative charge that results will be specified in section 2.5.3.2 of Exhibit D of the CHWM contract. Table 3.21 of Documentation shows the SCS Administrative charges that are calculated for the individual resources to which SCS is applied. Section II.P.2.(b) of the

GRSPs includes the formula for calculating the SCS Administrative Charge for the individual resources to which SCS is applied.

3.1.13.4 Additional PFp RSS Considerations

3.1.13.4.1 Forced Outage Rating

All generally recognized types of generating resources have a standard forced outage rating. This rating represents the average percentage of time that a generating resource is unavailable for load service due to unanticipated breakdown. BPA will use a minimum five percent forced outage rating for hydroelectric resources and seven percent for thermal resources. The Initial Proposal assumes a 10 percent forced outage rating for resources other than hydroelectric resources. Customers taking services that have charges including the use of a forced outage rating may request that BPA increase the forced outage rating for their resource, and those with a resource other than a hydroelectric resource may request that BPA decrease the forced outage rating to as low as seven percent.

3.1.13.4.2 Historical Generation Year Resource Amounts Adjusted for Schedules

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

3.1.13.4.3 Credits to the PFp Tier 1 Customer Cost Pools

Forecast revenue credits will be calculated from the RSS charges. All revenues except those from the Resource Shaping Charge will be credited to the appropriate PFp Tier 1 Customer Rate cost pools. The forecast revenue from the Resource Shaping Charge sales is a revenue credit to the Non-Slice cost pool. Additional information on these revenue credits is found in sections 3.1.2.1 and 3.1.2.2.

3.2 Priority Firm Exchange (PFx) Rate Design

The PF Exchange rate applies to participants in the Residential Exchange Program (REP) for sales of exchange energy pursuant to a Residential Sale and Purchase Agreement (RPSA) or the 2010 REP settlement agreement. Under either an RPSA or the settlement agreement, the PF Exchange rate is applied to BPA's sales of exchange energy, and the participating utility's Average System Cost (ASC) is applied to BPA's purchase of exchange energy, where the exchange energy is equal to the utility's eligible residential and small farm load. The difference between the amount BPA pays for exchange "purchases" and the amount BPA receives for exchange "sales" determines the amount of monetary REP benefits BPA pays the utility. The PF Exchange rate also applies to any actual power sales to exchanging utilities under contractual "in-lieu" provisions.

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

The two Base PFx rates are computed within RAM based on the average PF rate immediately prior to the section 7(b)(2) rate test. At this point of the ratemaking process, no 7(b)(2) rate protection costs have been determined and, therefore, the Base PFx rates bear no rate protection costs. The PFx rate applicable to IOUs (and any eligible COU without a CHWM contract) is computed by dividing all costs allocated to the PF rate pool divided by all PF rate pool loads and then adding a charge for delivering the exchange power to the customer. The PFx rate applicable to COUs with CHWM contracts is calculated in the same manner, except that the costs allocated to Tier 2 cost pools are excluded from the numerator, and loads served at Tier 2 rates are excluded from the denominator. The Base PFx rates are calculated in the same manner whether or not the REP settlement is adopted.

Under the REP settlement agreement, two utility-specific REP Surcharges replace utility-specific 7(b)(3) Supplemental Rate Charges. Both of the utility-specific charges are calculated in a similar manner. In both cases, the amount of 7(b)(2) rate protection costs allocated to the PFx rates is further allocated to each REP participant on a pro rata basis using REP benefits calculated using the Base PFx rates as the allocator. The amount of rate protection cost allocated to each REP participant is divided by the participant's exchange load to derive its utility-specific REP Surcharge (or 7(b)(3) Supplemental Rate Charge).

For each REP participant, the applicable Base PFx rate is added to its utility-specific REP Surcharge to determine its utility-specific PFx rate. For each month of the rate period, the participant will invoice BPA its exchange load for the prior month. BPA will multiply this invoiced exchange load by the difference between the participant's ASC and its PFx rate to calculate the amount of REP benefits payable to the participant.

3.3 Industrial Firm Power (IP) Rate Design

The rate design for the IP rate consists of 24 monthly/diurnal energy rates and 12 demand rates (one for each month).

3.3.1 IP Energy Rates

The IP rate design includes 24 monthly/diurnal energy rates, two for each month, one each for HLH and LLH. Monthly and diurnal differentiation of IP energy rates is performed based on the HLH and LLH differentiation of the PFp Melded rate (see section 3.1.12).

IP energy rates are determined by adjusting the PFp Melded rates by the Value of Reserves (VOR) provided by the DSI load, the net industrial margin, and the REP. See Documentation, Table 2.5.7.3.

3.3.1.1 IP Adjustment for Value of Reserves Provided

A VOR credit is included in the IP rate, as provided in section 7(c)(3) of the Northwest Power Act. See section 1.2.2. The FY 2012-2013 rate period DSI power sales forecast is 340 aMW. See Power Loads and Resources Study, section 2.4. Based on provisions of DSI contracts currently in place, these power sales are assumed to provide interruption reserve rights to BPA.

The first step for valuing interruption reserves provided by DSIs is to determine a marginal price for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve obligations, the cost of Operating Reserves (Supplemental) is used to establish the marginal value. The Operating Reserves documented in the Generation Inputs Study are provided by the Federal Columbia River Power System (FCRPS), and are available for any hour and on any day.

The second step in valuing the DSI reserves is to determine the quantity of reserves provided. To calculate this quantity, the load of aluminum DSIs available for interruption is reduced to account for wheel-turning load that cannot be curtailed. The wheel-turning load for aluminum DSIs is forecast to be 6 aMW. No wheel-turning amount is established for Port Townsend. The interruption reserves provided are 10 percent of the remaining DSI load. The VOR credit included in the IP-12 rate is 0.94 mills/kWh. See Table 3.22 of Documentation for calculation of the value of DSI reserves.

3.3.1.2 IP Rate Typical Margin

Another component of the IP rate is the typical margin, as provided in section 7(c)(2) of the Northwest Power Act. See section 1.2.2. The typical margin is based generally on the overhead costs that COUs add to the cost of power in setting their retail industrial rates. The typical margin included in the IP-12 rate is 0.68 mills/kWh. The methods and calculations used to determine the typical margin are discussed in detail in Appendix A.

3.3.1.3 REP Surcharge

The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be allocated to all other power sold, which includes power sold at the IP rate. See section 1.2.2. The cost of rate protection allocated to the IP rate is determined pursuant to the 2010 REP Settlement agreement and is included in the IP-12 rate. The IP-12 REP Surcharge is 7.74 mills/kWh. See Documentation, Table 2.4.14 for calculation of the REP Surcharge.

3.3.2 IP Demand Rates

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

As with the PFp Demand charge, the IP Demand billing determinant is applied to only a portion of the DSI peak demand placed on BPA. The IP Demand billing determinant in each billing month will be equal to the DSI’s highest HLH schedule, or metered amount, minus the average HLH schedule amount, or metered amount.

3.4 New Resources (NR) Rate Design

The rate design for the NR rate consists of 24 monthly/diurnal energy rates (one each for HLH and LLH for each month) and 12 demand rates (one for each month).

3.4.1 NR Energy Rates

Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and LLH differentiation of the PFp Load Shaping rates. See Documentation, Table 2.5.7.4.

The NR energy rates are determined by adjusting the PFp Load Shaping rates by an equal scalar until the NR energy rates recover the allocated NR revenue requirement minus the forecast Demand charge revenue. See Documentation, Table 2.5.7.4.

After the scaling process is complete, an REP Surcharge is added to each of the monthly/diurnal energy rates. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers be allocated to all other power sold, which includes power sold at the NR rate. See section 1.2.2. The cost of rate protection allocated to the NR rate is determined pursuant to the 2010 REP Settlement agreement. The NR-12 REP Surcharge is 7.74 mills/kWh. See Documentation, Table 2.4.14, for calculation of the REP Surcharge.

3.4.2 NR Demand Rates

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

As with the PFp Demand charge, the NR Demand billing determinant is only a portion of the peak demand placed on BPA. The NR Demand billing determinant will be equal to the highest NR Hourly Load during HLH less the average hourly HLH energy purchased in that particular month at the NR energy rates.

3.5 Firm Power Products and Services (FPS) Rate Design, Resource Support Services (RSS), and Transmission Scheduling Service (TSS)

Products and services available under this rate schedule are described in BPA's 2012 Rate Schedules and GRSPs. Sales under this rate schedule are discretionary: BPA is not obligated to sell any of these products, even if such sales will not displace PF/NR/IP sales. Products sold under the FPS-12 rate are at market-based or negotiated rates, and may have a demand component, an energy component, or both. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-12 rate.

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

3.5.1 Firm Power and Capacity Without Energy

When available, BPA sells firm power, including secondary energy, or firm capacity for use within the Pacific Northwest and outside of the Pacific Northwest. Such power sales are sold under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer. Sales of firm power may be subject to an REP Surcharge. The applicability of an REP Surcharge will be made by BPA at the time of the sale, as set forth in the 2010 REP Settlement agreement.

3.5.2 Supplemental Control Area Services

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

3.5.3 Shaping Services

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

3.5.4 Reservations and Rights to Change Services

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

3.5.5 Reassignment or Remarketing of Surplus Transmission Capacity

When available, BPA reassigns or remarkets its surplus transmission capacity that has been purchased from a transmission provider, including Transmission Services, consistent with the terms of the transmission provider's Open Access Transmission Tariff. BPA sells this surplus transmission capacity to parties within the Pacific Northwest and outside of the Pacific Northwest. Such services are sold under the FPS rate schedule at rates and billing determinants specified by BPA or as mutually agreed by BPA and the customer.

3.5.6 Services for Non-Federal Resources

For the first time, BPA is offering Forced Outage Reserve Service (FORS) and Transmission Scheduling Service (TSS) at posted FPS rates. FORS is one of the Resource Support Services and is offered under the FPS rate schedule to customers with resources that meet specific requirements specified in the CHWM contract. Forced outage reserve service for customers without CHWM contracts would be offered, if available, under the Reservations and Rights to Change Services part of the FPS rate schedule. TSS is not an RSS but is related to the services that comprise RSS. It is a required service for customers with resources that meet eligibility requirements specified in the CHWM contract and is also being offered under the FPS rate schedule. TCMS is also not an RSS but is related to TSS. It is an optional service for customers with resources that meet eligibility requirements specified in the CHWM contract and is also being offered under the FPS rate schedule.

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

3.5.6.1 Forced Outage Reserve Service (FORS)

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

3.5.6.1.1 FORS Pricing Summary

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

The FORS Charges include the following elements:

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

3.5.6.1.2 FORS Capacity Charge

FORS Capacity Rates. The rates used to calculate the FORS Capacity charge are based on the PFp Demand rates and are listed in the GRSPs, Section II.P.3.(a)(1).

FORS Capacity Billing Determinant. For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The firm capacity is calculated by the RSS module of RAM in the manner described for the DFS capacity billing determinant. Study section 3.1.13.2.2. The forced outage rating for a resource taking FORS has the same considerations as described in section 3.1.13.4.1.

FORS Capacity Charge. For each resource, the FORS Capacity charge is the product of multiplying the FORS Capacity rate by the FORS Capacity billing determinant for each month. The sum of the monthly values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in section 2.4.5.3 of Exhibit D of the CHWM contract. A wood waste resource example in Table 3.18 of Documentation shows the calculation of the FORS Capacity charge. Table 3.21 of Documentation show the FORS Capacity charges that are calculated for each resource currently requesting FORS. The formula for calculating the FORS Capacity charge for each individual resource to which FORS is applied is shown in Section II.P.3.(a)(2) of the GRSPs.

3.5.6.1.3 FORS Energy Charge

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

FORS Energy Rate. The rate for the energy provided during the first 24 hours of a forced outage will be the average of the hourly Powerdex Mid-C Price or its replacement during the hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index or its replacement for the applicable diurnal period the energy is provided. If any of the Mid-C prices specified above is less than zero, the FORS Energy rate calculation will be zero for such negative value.

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

FORS Energy Charge. For each resource, the FORS Energy charge is the product of multiplying the FORS Energy rate by the FORS Energy billing determinant. Section II.P.3.(b) of the GRSPs shows the formula for calculating the FORS energy charges for the individual resources to which FORS is applied.

3.5.6.2 Transmission Scheduling Service (TSS) and Transmission Curtailment Management Service (TCMS)

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

If a Load Following customer is served by transfer or is purchasing DFS or SCS services from BPA, it is required to have the TSS provisions added to its CHWM contract. Many customers meeting these criteria do not have a non-Federal resource with an e-Tag that must be scheduled to their load. Only customers that have a non-Federal resource that requires an e-Tag will be charged for TSS services. Pursuant to the Load Following CHWM contract, for a customer that is not required to take TSS given the criteria described above, TSS is an optional service if the customer wishes to have BPA produce the e-Tags for its resource(s). If a Load Following customer with a non-Federal resource is not required by its contract to take this service or elects not to take this service, it is required to supply replacement transmission or power when the resource's transmission path experiences an outage or curtailment. If it is unable to do so, it may face a UAI charge.

3.5.6.2.1 TSS/TCMS Pricing Summary

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

The TSS/TCMS charges include the following elements:

- A monthly TSS charge based on the dedicated resource megawatthour amounts found in Exhibit A of the Load Following CHWM contract for FY 2012 and FY 2013 for Specified and Unspecified Resource amounts for resources requiring an e-Tag. Although the contract states these values in megawatthours, BPA bills on kilowatthours, so the appropriate conversion is made.
- A TSS rate that is based on the Operations Scheduling costs for the two years of the rate period divided by the total megawatthours BPA has scheduled in the two most 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 will calculate 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, Realtime, and After-The-Fact functions) by the total megawatthours of power BPA scheduled in FY 2009 and FY 2010. The result is a 0.20 mills/kWh rate.

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 FY 2013 if this service applies in only FY 2013). The sum of the monthly values is divided by 24 (or 12 if the service applies in only FY 2013) 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 $1,080/month, then the monthly charge is capped at $1,080/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 2009 and FY 2010.

Examples for a wind resource and a biomass resource show how the TSS charge described above is calculated. See Documentation, Tables 3.18 and 3.20. Table 3.21 of the Documentation shows the individual TSS charges that are calculated for the individual resources to which only TSS is applied and individual resources to which TSS is applied in addition to other RSS products. Section II.P.4.(a)(3) of the GRSPs shows the formula for calculating the TSS charge for the individual resources to which TSS is applied.

3.5.6.2.3 TCMS Charge

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

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

TCMS Charge if Alternative Transmission is Provided. If Point-to-Point transmission is used for the alternate transmission path used to deliver the customer's eligible resource, for each resource the TCMS charge is the cost of the additional Point-to-Point transmission purchases plus any additional costs, including real power losses, associated with using the replacement transmission.

Section II.P.4.(b)(3) of the GRSPs shows the formula for calculating the TCMS charges for the individual resources to which TCMS is applied.

For the BP-12 rate period, the TCMS charge does not include a non-Firm Network or Point-to-Point Reservation Fee. BPA is reserving the right to include such a fee in future rate periods for customers wheeling their non-Federal resource to their loads on non-Firm Network or non-Firm Point-to-Point transmission.

The TCMS application to the Tier 2 rates is described in section 3.1.9.1.

3.5.6.3 TSS Charge Application to Tier 1 Augmentation

The TRM states that RSS pricing will be used to make Federal resource acquisitions financially equivalent to a flat block. TRM, section 8. In addition, Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. TRM, section 3.5. The one resource whose costs are allocated to Tier 1 Augmentation is Klondike III, a scheduled resource that requires an e-Tag. The RAM RSS module calculates a TSS Charge for this resource. This TSS Charge is added to the RSS charges for each year of the rate period that are allocated to the

Composite cost pool under the "Non-Slice Augmentation RSC Revenue Debit/(Credit)" line item.

3.5.6.4 Credits to the PFp Tier 1 Customer Rate Cost Pools

Forecast revenue credits are calculated from the RSS charges. All revenues, except those from the Resource Shaping Charge, are allocated as credits to the Composite Customer cost pools. The forecast revenue from the Resource Shaping Charge is allocated as a credit to the Non-Slice Customer cost pool. Additional information on these revenue credits is found in sections 3.1.2.1 and 3.1.2.2.

3.5.7 Unanticipated Load Service (ULS)

Under the FPS-12 rate schedule, the Resource Replacement (RR) rate will be applied to Unanticipated Load Service (ULS) for Above-RHWM load that is forecast to be served by a COU customer's Non-Federal Specified Resource, but such resource is not available due to a delay in coming on-line. The energy rate for the RR rate is equal to the Load Shaping rate or the projected market price calculated when a request for ULS is made, whichever is greater. See section 3.1.6.2 for a description of the Load Shaping rate. The demand rate is equal to the PFp demand rate, described in section 3.1.6.3 of this Study. The ULS under the FPS-12 rate schedule is specified in section II.U.4. of the GRSPs.

3.6 General Transfer Agreement Service Rate Design

Transfer Services are the transmission and distribution services BPA acquires from other transmission providers to transmit Federal power to BPA customers located within third-party-owned transmission systems. Transfer Service customers may be subject to one or two separate charges from BPA under the General Transfer Agreement Service (GTA-12) rate: (1) the General Transfer Agreement (GTA) Delivery Charge, and (2) the Transfer Service Operating

Reserve Charge. In addition to these charges, Transfer Service customers are responsible for the cost of any distribution upgrades associated with their respective points of delivery, as provided in the Supplemental Direct Assignment Guidelines (GRSPs, Section I.E.).

3.6.1 GTA Delivery Charge

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

Since 2002, the GTA Delivery Charge has mirrored the Transmission Services Utility Delivery Charge. For the FY 2010-2011 rate period, the Transmission Services Utility Delivery rate was set at $1.119 per kilowatt per month; GTA-10 was consistent with that rate. Power Services is continuing the application of the $1.119 per kilowatt per month rate and billing factor for the GTA-12 Delivery Charge.

The GTA Delivery Charge revenue forecast is approximately $2.5 million per year, as shown in Table 4.11 of Documentation. This revenue forecast was derived by applying the proposed GTA Delivery Charge of $1.119 per kilowatt per month to the forecast peak loads at the points of delivery at which customers currently pay the GTA Delivery Charge.

3.6.2 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is designed to address a potential change in Operating Reserve obligations. Currently, BPA does not pay Operating Reserves on third-party systems for the transmission of Federal power to Transfer Service customers because Transfer Service customers already pay the required Operating Reserve transmission charge. WECC has proposed a change to this requirement that would reduce the Operating Reserve obligation of the BPA Balancing Authority Area for Transfer Service customers and shift a portion of the obligation to the Balancing Authority Areas where the Transfer Service Customer conducts business. This change, if adopted, would shift a portion of the costs for Operating Reserves from Transfer Service customers to BPA.

In anticipation of this potential change, the Transfer Service Operating Reserve Charge for the FY 2012-2013 rate period is designed to mitigate the cost shift described above in the event the Commission adopts WECC's proposed change. The Transfer Service Operating Reserve Charge rate, if assessed, would be the same as the ACS-12 rate for Operating Reserves that Transmission Services charges to customers that have load in the BPA Balancing Authority Area.

Due to the uncertain nature of if and when WECC's proposed changes may be adopted by the Commission and implemented by the various transmission providers, the implementation of the Transfer Service Operating Reserve Charge has been conditioned upon the satisfaction of three criteria: (1) BPA serves the power customer by Transfer Service; (2) the Transfer Service customer does not pay Transmission Services for Operating Reserves based on 3 percent of the customer's load; and (3) BPA is assessed Operating Reserve charges from a third-party transmission provider to transfer Federal power to the power customer's load. Power Services intends to assess the Transfer Service Operating Reserve Charge only if all three criteria have been satisfied.

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

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4. REVENUE FORECAST

The revenue forecast calculates the expected level of revenue from power rates and other sources for the rate period, FY 2012-2013, as well as the current year, FY 2011. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect, and the second uses proposed rates. The revenue forecasts are used to test whether current rates and proposed rates will recover the power revenue requirement. Upon showing that revenues at current rates will not generate sufficient revenue to recover the power revenue requirement, a rate change is necessary, and revenues at proposed rates are generated. See Power Revenue Requirement Study, sections 3.2 and 3.3. Both forecasts are based on the Power Loads and Resources Study, 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 PFp revenues and IP revenues. All other revenues remain constant between the two forecasts.

In addition to forecasts of revenues, this study calculates power purchase expenses that are directly related to generation levels of surplus energy. Power purchases are included in the forecast for FY 2011-2013 and discussed in section 4.5.

Also included in the revenue forecast are revenue calculations for the current year, FY 2011. This forecast is needed 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) gross sales, described in section 4.1; (2) miscellaneous revenues, described in section 4.2; (3) generation inputs for ancillary, control area, and other services, described in section 4.3; and (4) Treasury credits, described in section 4.4. The change in organization from the WP-10 Final Proposal is designed to increase consistency with other BPA financial documents in terms of revenue categories. In addition, there are multiple new revenue categories compared to the WP-10 Final Proposal.

4.1 Revenue Forecast for Gross Sales

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

4.1.1 Firm Power Sales under Subscription and CHWM Contracts

For FY 2011, the revenues from Priority Firm power sales pursuant to Subscription contracts are calculated under the WP-10 rate structure, and revenues are reported for HLH energy, LLH energy, demand, load variance, and irrigation mitigation, as applicable. Additional details about this rate structure can be found in the 2010 Wholesale Power Rate Schedules, WP-10-A-02, Appendix B. Subscription revenues for FY 2011 are listed in Table 2, lines 3 – 9 and in Documentation, Table 4.1, lines 3 – 9.

For FY 2012 and 2013, revenues from PF power sales pursuant to CHWM contracts are computed using the product of (1) forecast loads assuming normal weather, documented in the Power Loads and Resources Study and accompanying Documentation; and (2) the appropriate PF rates derived by the Rate Analysis Model (RAM2012). Revenue forecasting inputs and results are managed and calculated using a database referred to as the Revenue Forecasting

Application (RFA) and calculated pursuant to the CHWM contracts. Revenues are reported for Tier 1 Composite (Slice and Non-Slice), Load Shaping, and Demand (including the Low Density Discount and Irrigation Rate Discount credits), and any additional Tier 2 or RSS charges.

4.1.1.1 Composite and Non-Slice Customer Charges

Revenues from each customer for the Composite and Non-Slice Customer charges are based on the customer's unique Tier 1 Cost Allocator (TOCA) and the customer's contractually specified products. Revenues obtained from the Composite and Non-Slice Customer charges represent the majority of revenues from firm power sales under CHWM contracts. Composite and Non-Slice revenues for FY 2012-2013 are listed in Table 3, lines 3 – 5, and Documentation, Table 4.2, lines 10 - 11.

4.1.1.2 Load Shaping Charge

The Load Shaping charge is designed to reflect the costs and benefits of shaping the Tier 1 System Capability to the monthly/diurnal shape of a customer's Below-HWM load. A charge to the customer results when the customer's shaped load is greater than its share of the Tier 1 System Output; the customer will receive a credit from BPA when the opposite occurs. The Load Shaping charge is described in detail in section 3.1.6.2, and an example calculation of the Load Shaping charge is available in Documentation, Table 4.6. Load Shaping revenues for FY 2012-2013 are listed in Table 3, line 6, and Documentation, Table 4.2, line 13.

4.1.1.3 Demand Charge

The Demand charge is applicable to customers purchasing Load Following or Block products. The Demand charge is calculated using customer-specific information including actual Customer Tier 1 System peak, average actual monthly Below-HWM load occurring in Heavy Load Hours, Contract Demand Quantity (CDQ), and Super Peak Credit (if applicable). Calculation of a customer's Demand charge is described in section 3.1.6.3, and an example calculation is available in Documentation, Table 4.6. Demand revenues for FY 2012-2013 are listed in Table 3, line 7, and in Documentation, Table 4.2, line 14.

4.1.1.4 Irrigation Rate Discount

The Irrigation Rate Discount (IRD) is a rate credit to eligible customers and provides a fixed rate discount on Tier 1 rates. Eligible irrigation loads during May, June, July, August, and September are identified in each customer's CHWM contract, and the irrigation load amount will not increase during the contract term. The discount does not apply to loads served at Tier 2 rates. A methodology for calculating an end-of-year true-up appears in GRSPs, Section II.H.2. Forecast credits for irrigation loads will be calculated using an IRD that is derived by multiplying the irrigation loads identified in the CHWM contracts multiplied by the IRD rate. The IRD is described in section 3.1.11, and an example calculation is available in Documentation, Table 4.7. IRD credits for FY 2012-2013 are listed in Table 3, line 8, and Documentation, Table 4.2, line 15.

4.1.1.5 Low Density Discount (LDD)

LDD is a credit to certain customers, generally in rural areas, to avoid adverse impacts of customers with low system densities. The LDD principles, eligibility criteria, and discount appear in the GRSPs, Section II.J. Under the TRM, LDD percentages are adjusted to provide a discount on purchases at Tier 1 rates that approximates the discount the customer would receive under non-tiered rates. An example calculation is available in Documentation, Table 4.8. LDD credits for FY 2012-2013 are listed in Table 3, line 9, and in Documentation, Table 4.2, line 16.

4.1.1.6 Tier 2 and Resource Support Services (RSS)

Tier 2 rates are based on a cost allocation that fully recovers the cost of BPA service to Above-RHWM load. Tier 2 Revenues are based on sales to customers that have elected to have BPA serve their Above-RHWM load, and revenues for FY 2012-2013 are listed in Table 3, line 10, and Documentation, Table 4.2, line 17.

RSS allows a customer to apply the variable output of a resource to serve its Above-RHWM load without having to guarantee a specific scheduled shape of this resource. These services are available for all specified non-Federal resources that Load Following customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources that Slice/Block customers contractually dedicate to serve their Total Retail Load. Revenues from these services are based on known services chosen by customers. Revenues for FY 2012-2013 are listed in Table 3, line 11, and Documentation, Table 4.2, line 18.

4.1.2 Industrial Power Sales to Direct Service Industrial Customers

BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the product of (1) forecast loads of 340 aMW for FY 2011-2013, documented in the Power Loads and Resources Study and accompanying Documentation; and (2) the appropriate IP rate from RAM2012. For FY 2011, the revenues for DSI customers are calculated using the WP-10 IP rate. Revenues for FY 2011-2013 are listed in Table 3, line 13, and Documentation, Table 4.2, line 20.

4.1.3 Pre-Subscription Sales

BPA provides power to certain customers under Pre-Subscription contracts. During FY 2011, there are eleven Pre-Subscription contracts, and during FY 2012-2013, there is one Pre-Subscription contract. The revenues from Pre-Subscription customers are derived by multiplying individual customer loads by the appropriate FPS rate, both of which are set pursuant to the Pre-

Subscription contracts. Revenues for FY 2011-2013 are listed in Table 3, line 14, and Documentation, Table 4.2, line 21.

4.1.4 Short-Term Market Sales

The revenue forecast includes revenues from the sales of surplus energy, which is energy in excess of that required to serve firm loads. For rate development purposes, the forecast of firm FCRPS output is based upon critical (1937) water conditions. FCRPS output, while uncertain, is expected to be greater than under 1937 water conditions, and thus surplus energy sales and revenue result. For FY 2011, the surplus energy revenue included in the revenue forecast is the average of the surplus energy revenues computed during RiskMod simulations of 50 games for each of 70 historical water years, for a total of 3,500 games. For FY 2012-2013, the surplus energy revenue is the median of the surplus energy revenues across 3,500 games. In both cases, this power is sold under the FPS rate schedule.

The revenue forecast for short-term market sales is computed using RiskMod to calculate monthly HLH and LLH energy surpluses for each of the 3,500 games, applying corresponding market prices developed for each game. See Power Risk and Market Price Study, section 2.6.3 and Documentation Table 21. Revenues for FY 2011 – 2013 is shown in Table 3, line 15, and Documentation, Table 4.2, line 22.

4.1.5 Long-Term Contractual Obligations

Long-term obligation contracts include the WNP-3 Exchange Settlements, a wind energy exchange, capacity and energy exchanges, and a seasonal power exchange. For FY 2011-2013, revenue from these contractual obligations is calculated pursuant to the individual contracts and then summed and added to the forecast as a group. Note that capacity and energy exchanges, as well as the seasonal power exchange, do not generate revenue. Revenue for FY 2011-2013 is listed in Table 3, line 16, and Documentation, Table 4.2, line 23.

4.1.6 Canadian Entitlement Return

The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the border. No revenues are generated from the delivery of this power, but energy amounts are listed in the revenue forecast to represent this system obligation. The average megawatt deliveries for FY 2011-2013 are listed in Table 3, line 17, and Documentation, Table 4.2, line 24.

4.1.7 Renewable Energy Certificates

Renewable Energy Certificates (REC) are the environmental attributes corresponding to one megawatthour of generation from a renewable energy resource. BPA sells a portion of the RECs it receives as part of its energy purchases from six wind projects. Under Subscription contracts, 43 preference customers have rights to purchase RECs through FY 2016. BPA forecasts that these preference customers will exercise their full rights up to the limits set in the Subscription contracts; this forecast quantity is about 40 aMW. The price for the RECs for FY 2012-2013 will be set outside this rate proceeding pursuant to the terms of the contracts. BPA will establish the price not later than May 16, 2011. The forecast price for this Study is the same as the rate for Environmentally Preferred Power in FY 2011. After eligible preference customers have exercised their contract REC purchase rights, the RECs remaining in BPA's inventory for FY 2012-2013 will be distributed on a pro-rata basis to all CHWM customers based on customers' RHWMs. These RECs are distributed at no additional charge to the customers and do not generate any revenue for Power Services. See Power Rates Policy Testimony, BP-12-E-BPA-11. Revenues for RECs in FY 2012-2013 are listed in Table 3, line 18, and Documentation, Table 4.2, line 25.

4.1.8 Other Sales

Other sales include revenues from Network Wind Integration Service and from the Storage and Shaping Service, which shapes the variable output for a preference customer's share of a wind project. For FY 2011, 2012, and 2013, the rates for both of these services are set in the respective contracts, then adjusted each fiscal year for inflation. The amount of capacity used as the billing factor for these services is also set in the contracts but remains constant over the length of the contract. Other sales also include miscellaneous revenues from transfer customers and forecast revenues from the Slice True-Up, which is applicable only for FY 2011. Other sales revenue for FY 2011-2013 is listed in Table 3, line 19, and Documentation, Table 4.2, lines 26 - 29.

4.2 Revenue Forecast for Miscellaneous Revenues

Miscellaneous Revenues include revenues from Energy Efficiency, Downstream Benefits, and USBR power for irrigation. Energy Efficiency revenues are received by BPA as reimbursements for costs relating to implementation of various energy efficiency projects. For FY 2011-2013, revenues from Energy Efficiency are calculated by estimating project expenditures. These revenues are wholly offset by the associated expenditures, which are recorded on the expense ledger.

Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated planning and operation of U.S. Army Corps of Engineers (COE) and USBR upstream storage reservoirs as part of the Pacific Northwest Coordination Agreement. For FY 2011-2013, revenues from downstream benefits are calculated by applying a forecast of the operations and maintenance costs adjusted for inflation to the energy amounts from the most recent study conducted by the Northwest Power Pool (NWPP). The NWPP conducts a study each year on behalf of the utilities to calculate the energy amounts used in determining the downstream benefits.

USBR power for irrigation includes power that has been reserved from the FCRPS for use at USBR projects. For revenue forecasting purposes, power that has been reserved to USBR irrigation projects is classified as either "Reserved Power" or "Irrigation Pumping Power." Revenue from Reserved Power for FY 2011, 2012, and 2013 is forecast in equal monthly amounts based on an annual amount that is aggregated for USBR projects. The annual aggregated amounts are forecast based on historical information provided by the USBR. Revenue from Irrigation Pumping Power for FY 2011, 2012, and 2013 is calculated using the forecast irrigation pumping load times the price set in individual contracts. Miscellaneous revenues for FY 2011-2013 are listed in Table 3, line 21, and Documentation, Table 4.2, lines 31 - 36.

4.3 Revenue Forecast for Generation Inputs for Ancillary, Control Area, and Other Services and Other Inter-Business Line Allocations

Power Services receives revenue from Transmission Services for providing generation inputs for ancillary and control area services. This revenue forecast includes generation inputs for Regulating Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Operating Reserves. Power Services receives revenue from Transmission Services for providing generation inputs for other services, including Synchronous Condensing, Generation Dropping, Energy Imbalance, and Generation Imbalance. Other inter-business line allocations revenues include Redispatch, Segmentation of COE and USBR network and delivery facilities costs, and station service. All these generation inputs are explained in the Generation Inputs Study. Revenues are listed in Table 3, line 22, and Documentation, Table 4.2, lines 37 - 50.

4.4 Revenue from Treasury Credits

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

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

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

Program and capital expenses relating to the fish and wildlife programs are discussed in the Power Revenue Requirement Study. The methodology for estimating the replacement power purchases resulting from changes in hydro system operations to benefit fish and wildlife is described in section 3.3.1 of the Power Loads and Resources Study. The cost of the increased purchases is estimated using RiskMod and the market price forecast and is included in the Power Risk and Market Price Study, section 2.6.1 and Documentation, Table 16. Revenue from 4(h)(10)(C) credits is listed in Table 3, line 23, and Documentation, Table 4.2, line 51.

4.4.2 Colville Settlement Credits

The Colville Settlement Act Credits are discussed in section 1.2.3 of the Power Revenue Requirement Study. The Colville Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. BPA receives annual credits from the U.S. Treasury against payments due the U.S. Treasury to defray a portion of the costs of making payments to the Colville Tribes. The Treasury credit for the Colville Settlement in FY 2012 and FY 2013 is set by legislation at $4.6 million per year [Public Law No. 103-436; 108 Stat. 4577, as amended] and is listed in Table 3, line 24, and Documentation, Table 4.2, line 52.

4.5 Power Purchase Expense Forecast

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

4.5.1 Augmentation Purchase Expense

As explained in section 3.1.2.1.3 of the Power Loads and Resources Study, the forecast of firm FCRPS output is based upon critical (1937) water conditions. The forecast annual firm FCRPS output plus other Federal resources is not adequate to meet annual average firm loads. Therefore, system augmentation is added to Federal resources to balance firm annual resources with firm annual loads. The Loads and Resources Study projects the need to acquire system augmentation of 329 aMW in FY 2012 and 454 aMW in FY 2013 to meet firm loads. See Power Load and Resources Study, section 4.2.

In addition, BPA is purchasing Excess Requirements Energy (ERE) from two Slice customers in the amount of 10.7 aMW in FY 2011. ERE is an amount of requirements power that is determined to be in excess of a Slice customer's Net Requirement. Pursuant to Exhibit N of the Subscription Block and Slice Power Sales Agreement and any related Exhibit N Settlement

Agreement, BPA has the right to purchase ERE from Slice customers under certain conditions. The ERE amounts are deducted from the aggregate augmentation amounts to determine the augmentation amount used in this Study. Due to expiration of Subscription contracts effective in FY 2012, ERE augmentation will no longer be available to BPA after FY 2011.

The expense for the augmentation amounts of 329 aMW in FY 2012 and 454 aMW in FY 2013 is based on projected prices using the AURORAxmp model assuming critical water conditions. See Power Risk and Market Price Study, section 2.6.2, and Documentation, Table 17. These prices and the corresponding cost of these augmentation purchases are documented in that same Documentation, Table 17. Augmentation purchase amounts for FY 2011-2013 are listed in Table 3, line 26, and Documentation, Table 4.2, lines 54 - 56.

4.5.2 Balancing Power Purchases

Balancing power purchases are calculated by RiskMod, which finds any monthly HLH and LLH energy deficits by simulations of 50 games in each of the 70 water years, for a total of 3,500 games, and applying the corresponding market prices developed for each game. Similar to the treatment of short-term market sales, the mean value for balancing purchases over the 3,500 games is reported for FY 2011, and the median value is reported for FY 2012-2013. Total balancing purchase expense for FY 2011-2013 is listed in Table 3, line 27, and Documentation, Table 4.2, line 57. A full description is available in the Power Risk and Market Price Study, section 2.6.3, and Documentation, Table 22.

4.5.3 Other Power Purchases

The majority of other power purchases is from committed winter hedging purchases BPA has made to cover forecast HLH energy deficits during winter months under many water conditions. In those months and water years where firm loads exceed resources, these winter hedging purchases reduce balancing purchases. Conversely, in those months and water years where resources are sufficient to serve firm loads, these winter hedging purchases increase the amount of surplus sales. RiskMod accounts for the energy relating to winter hedging purchases in the balancing purchases category. However, the amount of expense is included separately. The reporting of hedging contracts differs from that of the WP-10 Final Proposal, where both expense and energy were included in balancing purchase expense. The reason for this reporting change is that these purchases are contractual obligations and are viewed as committed purchases in the context of the revenue forecast.

The cost of Tier 2 power is also included in other power purchases, as are other miscellaneous contracts. Total other power purchase expense for FY 2011-2013 is listed in Table 3, line 28, and Documentation, Table 4.2, line 58.

4.6 Summary Table of Power Revenues

A detailed table of power revenues is available in Tables 2 and 3 and in Documentation, Tables 4.1 and 4.2.

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5. RATE SCHEDULES

The power rate schedules establish the applicability of each rate schedule to products that BPA offers, the rates for the products, the billing determinants to which the rates are applied, and references to sections of the GRSPs that apply to each rate schedule. The proposed Power rate schedules described in this section are presented in their entirety in BP-12-E-BPA-09.

5.1 Priority Firm Power Rate, PF-12

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

5.1.1 Firm Requirements Power under a CHWM Contract

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

5.1.2 Firm Requirements Power under a contract other than a CHWM contract (the Melded Rate Option)

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

5.1.3 PF Exchange Rate

The PF Exchange rates apply to sales under a Residential Purchase and Sale Agreement or the 2010 REP settlement agreement. A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program power.

5.2 New Resources Firm Power Rate, NR-12

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

5.3 Industrial Firm Power Rate, IP-12

The IP-12 rate schedule is available for firm power sales to DSIs, as defined by the Northwest Power Act, pursuant to section 5(d). The IP-12 rate includes energy and demand rates. DSIs purchasing power pursuant to the IP-12 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

5.4 Firm Power Products and Services Rate, FPS-12

The FPS-12 rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change

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

5.5 General Transfer Service Agreement Rate, GTA-12

The GTA-12 rate schedule includes the GTA Delivery Charge and the Transfer Service Operating Reserve Charge applicable to customers served under a general transfer agreement.

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6. GENERAL RATE SCHEDULE PROVISIONS

The GRSPs describe the adjustments, charges, and special rate provisions applicable to the various rate schedules. The GRSPs also define the power products and services BPA offers and define other applicable terms. This section includes brief descriptions of provisions that are not described elsewhere in the Study. The proposed GRSPs described in this section are presented in their entirety in BP-12-E-BPA-09.

6.1 Supplemental Direct Assignment Guidelines

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

6.2 Conservation Surcharge

Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge recommended by the Northwest Power and Conservation Council pursuant to section 4(f)(2) of the Northwest Power Act. BPA does not currently anticipate applying such a surcharge in the FY 2012-2013 rate period. See GRSPs, Section II.A.

6.3 Cost Contributions

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

6.4 Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward rate adjustment mechanism that can respond to the financial risks BPA faces before BPA has another chance to set rates during a full rate case. If stated conditions are met, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year. See GRSPs, Section II.C, and Power Risk and Market Price Study, section 3.2.4.

6.5 Dividend Distribution Clause (DDC)

The DDC is a downward rate adjustment mechanism that returns accumulated net revenues to customers when BPA's cash reserves exceed a pre-defined level. If stated conditions are met, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the applicable year. See GRSPs, Section II.D, and Power Risk and Market Price Study, section 3.2.5.

6.6 DSI Reserves Adjustment

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

6.7 Flexible New Resource Firm Power Rate Option

The Flexible NR rate option, offered at BPA's discretion, allows NR-12 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the NR-12 rate schedule. The GRSP describes the factors that will be considered in such modifications. See GRSPs, Section II.F.

6.8 Flexible Priority Firm Power Rate Option

The Flexible PF rate option, offered at BPA's discretion, allows PF-12 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the PF-12 rate schedule. The GRSP describes the factors that will be considered in such modifications. See GRSPs, Section II.G.

6.9 The NFB Mechanisms

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

6.10 Priority Firm Power (PF) Shaping Option

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

6.11 REP Surcharge Adjustment

The Residential Exchange Program Surcharge is a utility-specific addition to one of the Base PF Exchange rates that recovers each REP participant's allocated share of rate protection provided pursuant to section 7(b)(2) of the Northwest Power Act. Each REP participant's initial REP Surcharge is determined in a section 7(i) rate proceeding based on a Base PF Exchange rate and the Average System Cost (ASC) and forecast exchange loads of all utilities assumed in ratemaking to participate in the Residential Exchange Program. Each REP participant's initial REP Surcharge is displayed in section 6.1 of the PF-12 rate schedule. Each REP Surcharge is subject to change during the rate period if qualifying events occur. These events include a change in a participant's ASC during the rate period due to the addition or removal of a resource from a participant's resource portfolio or the planned addition of a new large single load in the service territory of the participant. The procedures for modifying the REP Surcharges of all REP participants are codified in this GRSP. See GRSPs, Section II.O, for the procedures.

6.12 TOCA Adjustment

For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA for each year of the rate period is calculated in the BP-12 7(i) process. A customer's TOCA for a fiscal year may be adjusted to account for a significant change in the customer's total load as detailed in GRSPs, Section II.T.

6.13 Unanticipated Load Service

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2011, that results in an unanticipated increase in a customer's load placed on

BPA during the FY 2012-2013 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a customer that adds load through retail access, including load that was once served by the customer and returns from under retail access. See GRSPs, Section II.U.

6.14 Unauthorized Increase Charges

The Unauthorized Increase (UAI) charge is a penalty charge to customers taking more power from BPA than they are contractually entitled to take. The UAI rate is the greater of 150 mills/kWh or 2.0 times the highest hourly Powerdex Mid-C Index price for firm power for the month. See GRSPs, Section II.V.

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7. SLICE

7.1 Slice True-Up Adjustment

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

7.2 Composite Cost Pool True-Up

The Composite Cost Pool True-Up refers to the calculation of the annual Slice True-Up Adjustment for the Composite cost pool. For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite cost pool will be calculated by:

(1) subtracting:

- (i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite Cost Pool for the applicable fiscal year of the rate period from
- (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;

(2) dividing the difference determined in (1) above by the sum of the actual Composite cost pool TOCAs for that fiscal year (TOCAs are determined in accordance with TRM section 5.1.1 based on the Annual Net Requirement for Slice customers and computed consistent with the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following customers); and

(3) multiplying the quotient by each Slice customer's Slice Percentage for the applicable fiscal year.

As part of the Composite Cost Pool True-Up, the Firm Surplus and Secondary Adjustment from Unused RHWM will be revised to reflect the adjusted TOCAs for each fiscal year as described above in section 1.2 and the resulting revenue difference between a sale at the posted Composite Customer rate and at the rate case-determined value of Unused RHWM. For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool. See GRSPs, section II.R., for a description of the Composite Pool True-Up and the calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM. Table H of the GRSPs, the Composite Cost Pool True-Up Table, contains the forecast expenses, revenue credits, and adjustments that will be the basis when compared to actual expenses, revenue credits, and adjustments for the Composite Cost Pool True-Up calculation. *Id.*

7.3 Treatment of Certain Expenses, Revenue Credits, and Adjustments in the Composite Cost Pool True-Up

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

7.3.1 System Augmentation Expenses

System augmentation expenses are included in the FY 2012-2013 Composite cost pool. Part of these augmentation expenses is a cost for service to non-Slice customers’ Above-RHWM load that is served at Load Shaping rates. For a description of these system augmentation expenses, see section 3.1.3.3.

System augmentation expenses will not be subject to the Composite Cost Pool True-Up. However, implicit in the Composite Cost Pool True-Up of the firm surplus and secondary adjustment for Unused RHWM, and implicit in the Composite Cost Pool True-Up for the DSI revenue credit, are adjustments that reflect the effects of additional power purchases (or lack thereof) or additional power sales to the market. See section 3.1.3.2 of this Study for a description of the treatment of the firm surplus and secondary adjustment for unused RHWM and the DSI revenue credit for Composite Cost Pool True-Up purposes.

BPA's purchases of output from the Klondike III resource is a Tier 1 augmentation expense, and the Composite cost pool includes the cost of Resource Support Services (RSS) and Resource Shaping Charges (RSC) to shape the generation output of Klondike III into a flat annual block of power. Because the RSS and RSC charges financially convert the variable output of Klondike III to a firm annual block of power, the augmentation expense and RSS and RSC costs associated with generation output from the Klondike III resource will not be subject to the Composite Cost Pool True-Up.

7.3.2 Balancing Augmentation Adjustment

The Balancing Augmentation Adjustment is a credit to the Composite cost pool to offset increased system augmentation expenses due to Above-RHWM load that is served at Load Shaping rates. See section 3.1.3.3. The Balancing Augmentation Adjustment will not be subject to the Composite Cost Pool True-Up.

7.3.3 Firm Surplus and Secondary Adjustment from Unused RHWM

The Firm Surplus and Secondary Adjustment from Unused RHWM will be subject to the Composite Cost Pool True-Up. The methodology specified in the GRSPs, section II.R.1.a., will be used to calculate the actual firm surplus and secondary adjustment from Unused RHWM for purposes of the Composite Cost Pool True-Up. The actual Firm Surplus and Secondary Adjustment from Unused RHWM will be calculated by starting with the rate case forecast for the firm surplus and secondary adjustment and adding dollar amounts to reflect the change in the sum of actual TOCAs from the sum of forecast TOCAs.

The calculation of the actual firm surplus and secondary adjustment reflects the fact that when the sum of actual TOCAs is greater than the sum of forecast TOCAs, additional power is sold to customers at the Composite Customer rate, and it is assumed that additional costs are incurred in the form of forgone market sales or increased power purchases.

When the sum of actual TOCAs is less than the forecast TOCAs, the calculation of the actual firm surplus and secondary adjustment reflects the fact that when the sum of actual TOCAs is less than the sum of forecast TOCAs, less power is sold to customers at the Composite Customer rate, and it is assumed that more power is sold in the market or fewer power purchase costs are incurred.

7.3.4 DSI Revenue Credit

The forecast costs associated with service to the DSIs are included in the Composite cost pool. See TRM, section 3.2.1.3. DSI revenues received by BPA are included in the Composite cost pool as credits. The DSI revenue credit will be subject to the Composite Cost Pool True-Up.

For purposes of the Composite Cost Pool True-Up, an actual DSI revenue credit will be calculated. For details on how the actual DSI revenue credit will be calculated, see GRSPs, section II.R.1.(b).

The calculation of the actual DSI revenue credit starts with the forecast DSI revenue credit and makes an adjustment to the forecast to calculate the actual DSI revenue credit. When the actual DSI sales are greater than the rate case forecast DSI sales, it is assumed that additional power is sold to the DSIs at the IP rate, and additional costs are incurred in the form of forgone market sales or increased power purchases. The adjustment to the forecast DSI revenue credit reflects the revenues from the additional power sold to the DSIs and the additional costs that are incurred.

When the actual DSI sales are less than the rate case forecast DSI sales, it is assumed that less power is sold to DSIs at the IP rate, and more power is sold in the market, or it is assumed that such power may be used to meet BPA obligations so that fewer power purchase costs are incurred. The adjustment to the forecast DSI revenue credit will reflect these effects. The adjustment will also include any DSI take-or-pay revenues, if applicable.

7.3.5 Unspent Green Energy Premium (GEP) Revenues

For ratesetting purposes, a forecast amount of unspent GEP revenue balance remaining at the end of FY 2011 will be applied as a contra-expense in FY 2012-2013 against certain forecast expenses. See 2010 Integrated Program Review Final Close-Out Letter and Report, October 27, 2010. The contra-expense will be subject to the Composite Cost Pool True-Up. The contra-expense included in the Composite cost pool for ratesetting purposes is a forecast of the remaining balance of unspent GEP revenues as of the end of FY 2011. However, the exact amount of the remaining balance of unspent GEP revenues as of the end of FY 2011 will not be known when rates are established. The actual remaining balance of unspent GEP revenues will be calculated after audited actual financial data is available to BPA for FY 2011. The difference between the actual unspent GEP revenues and the forecast of the contra-expense included in the Composite cost pool for ratesetting purposes will be tracked for Composite Cost Pool True-Up purposes. In any given fiscal year, however, the actual contra-expense cannot exceed the actual eligible expenses.

GEP revenues earned in FY 2012-2013 are a revenue credit in the FY 2012-2013 Composite cost pool. This revenue credit will be subject to the Composite Cost Pool True-Up.

7.3.6 Interest Earned on the Bonneville Fund

TRM section 2.5 states that future circumstances may occur that make it reasonable and fair to make additional adjustments to the size of the base amount of financial reserves attributed to the Power function as of October 1, 2001. The TRM describes several circumstances that could occur. The base amount ($495.6 million) is the amount on which an interest credit is calculated for ratemaking purposes for crediting to the Composite cost pool.

Table 4 displays the circumstances and the related adjustments to the size of the base amount ($495.6 million).

The amounts contained in Table 4 have not been shared with or collected from Slice customers through a prior Slice True-Up, so these amounts will be adjustments to the size of the base amount of financial reserves. The payments or funds that BPA received are reflected as negative amounts in Table 4 and will increase the size of the base amount of financial reserves. BPA's payments for settlements or judgments or BPA's write-off of bad debt expense are reflected as positive amounts in Table 4 and will decrease the size of the base amount of financial reserves.

To the extent that BPA receives payments or makes payments during a fiscal year of the FY 2012-2013 rate period and the payments can be categorized into one of the types of receipts or payments described in the TRM, and those receipts or payments have not been proportionally allocated to Slice customers through their Slice True-Up Adjustment Charges during the rate period, then BPA will make an adjustment to the size of the base amount of financial reserves.

The interest credit on the financial reserves amount will be subject to the Composite Cost Pool True-Up. The actual interest credit calculated on the base amount of financial reserves can change from forecast interest credit due to changes in interest credit calculation factors from forecast factors. See Revenue Requirement Study Documentation, section 5, for a description of how the interest credit calculation factors can change from final rate case studies.

7.3.7 Bad Debt Expenses

Bad debt expenses could be allocated between the Composite cost pool and the Non-Slice cost pool. TRM Table 2A, at 122. There is no forecast bad debt expense for the FY 2012-2013 period for ratesetting purposes. If a bad debt expense is identified and accounted for in BPA's actual audited financial reports for a given fiscal year, there would first be a determination of whether the expense would be included in the actual expenses and revenue credits that are allocable to the Composite cost pool in the applicable fiscal year of the rate period. If so, then the expense may be included for purposes of the Composite Cost Pool True-Up, and the bad debt expense would be allocated according to the principle of cost causation. TRM, section 2.1.

Any bad debt expense associated with a sale to any customer that purchased Federal power exclusively at the FPS-02, FPS-07, FPS-07S, and FPS-12 rates would be excluded for Composite Cost Pool True-Up purposes. Bad debt expenses associated with sales of power at only these FPS rates are related solely to BPA's sales of surplus power after the inception of the Slice product and not to sales of requirements power. The expenses and revenues from such sales are attributable to BPA's marketing of secondary energy after the inception of the Slice product, and are included in the Non-Slice cost pool. See TRM, section 2.2.3.

Any bad debt expense associated with a sale to a customer that purchases power at only the PF or IP rate will be included for purposes of the Composite Cost Pool True-Up. In addition, any bad debt expense associated with a sale to a customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both the IP rate and the FPS rate, will be included for purposes of the Composite Cost Pool True-Up. Such bad debt expense will be included because these transactions are reflected on single power bills; that is, a customer that purchases power at both PF rates and FPS rates will receive a single bill for these purchases. If the receivable amount associated with this single bill is determined by BPA to be uncollectible, the bad debt expense associated with this receivable will not be disaggregated further for any analytical purpose. Therefore, the entire receivable is considered to be a PF purchase, and if it is determined to be uncollectible, the bad debt expense associated with this receivable will be included for purposes of the Composite Cost Pool True-Up.

Any future bad debt expense related to write-offs of any outstanding California Independent System Operator (CAISO) or California Power Exchange (Cal PX) receivables for transactions prior to October 1, 2001, would be excluded for Composite Cost Pool True-Up purposes.

Such bad debt expenses were specifically excluded as part of the Slice Settlement Agreement (07PB-12273), which was effective until September 30, 2011. This exclusion is proposed for continuation for the BP-12 rate period.

Any bad debt expenses related to write-offs of any outstanding receivables arising out of FPS power sales transactions (other than with CAISO or Cal PX) prior to October 1, 2001, will be included for Composite Cost Pool True-Up purposes. Such bad debt expenses were not specifically excluded as part of the Slice Settlement Agreement. Such bad debt expenses will be included for Composite Cost Pool True-Up purposes because FPS power sales transactions prior to October 1, 2001, benefited all customers, as there was no Slice product prior to that date.

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

For the categories of bad debt expenses specifically excluded from the Subscription Slice True-Up Adjustment Charges since FY 2002, any related revenue recoveries of such bad debt expenses will be excluded for purposes of the Composite Cost Pool True-Up. This treatment is consistent with cost causation principles. See TRM, section 2.1. Since Slice customers did not share in these bad debt expenses, Slice customers will not share in any related revenue recoveries.

7.3.8 Settlement or Judgment Amounts

BPA payments or BPA receipts of money related to settlements and judgments would be allocated on a case-by-case basis to either the Composite cost pool or the Non-Slice cost pool. If an amount (payment or receipt) is accounted for, after rates were set, in BPA's actual audited financial reports for any given fiscal year, there would be a determination of whether it would be included or excluded for Composite Cost Pool True-Up purposes. Such a determination would be made based on the principle of cost causation. See TRM, section 2.1.

7.3.9 Transmission Costs for Designated BPA System Obligations

Transmission and Ancillary Services expenses are allocated between the Composite cost pool and the Non-Slice cost pool. See TRM, Table 2A.

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

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

Any revenue from resales of transmission that appear to be the result of BPA sales of unused transmission inventory associated with set-aside transmission will be excluded for Composite Cost Pool True-Up purposes. Such revenues will be excluded from the Composite Cost Pool True-Up to be consistent with the principle of no Composite Cost Pool True-Up of transmission expenses for Designated BPA System Obligations. Since the cost of additional transmission purchased (or of using non-Slice transmission inventory) to serve Designated BPA System Obligations in excess of what was forecast in the rate case will not be included in the Composite Cost Pool True-Up, such principle requires revenues from sales of surplus transmission inventory also be excluded from the Composite Cost Pool True-Up.

7.3.10 Transmission Loss Adjustment

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

The transmission loss adjustment will not be subject to the Composite Cost Pool True-Up.

7.3.11 Resource Support Services Revenue Credit

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

7.3.12 Tier 2 Rate Adjustments

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

The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by Power Services. For a description of this adjustment, see section 3.1.7.1. The Tier 2 overhead cost adder will be included in the Composite cost pool. This adjustment will be estimated for ratesetting purposes and not subject to the Composite Cost Pool True-Up.

The Tier 2 risk adder is an adjustment for any risks associated with resource costs that Power Services acquires for service to Tier 2 load. This adjustment is zero for the FY 2012-2013 rate period because no risk mitigation treatment is necessary. See section 3.1.7.4. This adjustment will not be subject to the Composite Cost Pool True-Up.

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

7.3.13 Residential Exchange Program (REP) Expense and Expense Reduction for Lookback Credit Amount

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

For the Composite Cost Pool True-Up Table, the forecast REP expense will reflect reductions for any Lookback credit amounts for FY 2012-2013 that are expected to be paid. The actual REP expense will also reflect reductions for the same Lookback credit amounts. By reflecting the reductions for the Lookback credit amounts in the forecast REP expense in the Composite Cost Pool True-Up Table, the effect of such reductions in actual REP expense is removed from the Composite Cost Pool True-Up, and Slice customers will not receive a share of this reduction in expense through their Slice True-Up Adjustment Charges. Slice customers will receive their Lookback credit amounts on their monthly bills.

The Composite Cost Pool True-Up Table will reflect annual Composite cost pool totals that are different from the Composite cost pool total calculated in RAM for setting the Composite Customer rate. The differences are due to 1) the Lookback credit amount that is reflected as an expense reduction in BPA's financial accounts at the end of the applicable fiscal year, and 2) the different annual shape of the benefit payments to REP participants. These differences are appropriate for Composite Cost Pool True-Up purposes.

The Composite Cost Pool True-Up Table contains a forecast REP expense that will be comparable to what actually will be paid to REP participants, so that there is no forecast Composite Cost Pool True-Up for this expense.

7.4 Slice Cost Pool True-Up

The Slice Cost Pool True-Up refers to the calculation of the annual Slice True-Up Adjustment for the Slice Cost Pool, which is described in the TRM. See TRM, section 2.72. The Slice cost pool is shown in Table I of the GRSPs in section II.R. Slice expenses and credits are forecast to be zero in FY 2012-2013. If there are any actual Slice expenses and credits incurred during the rate period, such expenses and credits will be subject to the Slice Cost Pool True-Up.

7.5 Adjustment of Slice Percentages for Additional CHWM for Jefferson County PUD

BPA will establish an Additional CHWM for Jefferson County PUD, a new public utility during the 2011 CHWM Process. Once the amount of the Additional CHWM is set, BPA will proportionally adjust customers' Slice Percentages, pursuant to the terms of Exhibit K of the Slice and Block contract. See TRM, section 3.6.1. The adjustment in percentages will be a customer's Slice Percentage multiplied by the ratio of: (1) Initial CHWM to (2) Initial CHWM plus Additional CHWM.

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8. AVERAGE SYSTEM COSTS

8.1 Overview of Average System Cost and the Residential Exchange Program

One of the components of the REP is the participating utilities' Average System Costs (ASC), which are determined in a separate ASC Review Process that BPA conducts pursuant to the substantive and procedural requirements of the 2008 ASC Methodology (ASCM). *See* 2008 ASCM, 18 C.F.R. § 301, *et seq*. The 2008 ASCM is an administrative rule that governs BPA's calculation of ASCs. The Federal Energy Regulatory Commission granted final approval to the 2008 ASCM on September 15, 2009.

Although ASCs are not determined in BPA's power and transmission rate proceedings, ASCs nonetheless are used to develop the forecast of exchange resource costs that BPA must collect in rates for the rate period, and the REP benefits paid to exchanging utilities.

In this rate case, BPA is establishing rates based on a proposed 2010 REP Settlement Agreement. The total IOU REP benefits for FY 2012-2013 (Scheduled Amounts) are established in the proposed Agreement. BPA is reviewing the terms of the proposed 2010 REP Settlement Agreement for compliance with the Northwest Power Act in a separate proceeding referenced as REP-12. Consistent with the Scheduled Amounts in the proposed 2010 REP Settlement Agreement, the REP benefits for participating IOUs are based on the IOUs' respective ASCs and REP exchange loads. Thus, IOUs' ASCs and REP exchange loads for FY 2012-2013 are needed to determine the REP benefits provided to individual IOU participants consistent with the proposed 2010 REP Settlement Agreement.

8.2 Overview of ASC Determinations

An ASC is calculated by dividing a utility's allowable resource costs (Contract System Cost) by the utility's allowable load (Contract System Load). The quotient is the utility's ASC ($/MWh). Contract System Cost is the sum of the utility's allowable generation- and transmission-related costs and overheads. Contract System Load is the sum of the total retail sales of a utility, as measured at the meter, plus distribution losses, less any New Large Single Loads (NLSLs), if applicable.

The ASCs used in the BP-12 Initial Proposal were determined in Draft ASC Reports published on November 19, 2010. These Draft ASC Reports reflect the most current estimates of utilities' ASCs for the BP-12 rate period. Draft ASC Reports were issued for nine utilities: Avista Utilities, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark County PUD, Franklin County PUD, and Snohomish County PUD.

The Draft Report ASCs shown in Table 5.4 of the Documentation are annual weighted averages for each utility. The actual ASC for each utility will change if the utility adds a new resource, retires an existing resource, or adds an NLSL. This revised ASC takes effect the month after a new resource comes on line, an existing resource is retired, or a new NLSL begins taking service. The weighted average ASCs are calculated using the monthly gross exchange costs, REP exchange loads, and monthly ASCs based on forecast dates of ASC changes. *See* Documentation, Table 5.1; Table 5.2; Table 5.3; and Table 5.4.

It is currently expected that, under the proposed 2010 REP Settlement, participating IOUs will agree to refrain from filing for ASC revisions based upon new resources. New resources added during the Exchange Period (the Exchange Period is identical to the rate period) are the most likely source of ASC revisions. If the proposed REP Settlement is adopted, the ASCs that are effective on the first day would likely persist throughout the Exchange Period. Therefore, "day-one" ASCs have been developed for use in establishing rates under the proposed REP Settlement. The day-one ASCs are shown in Table 2.1.3 of the Documentation.

8.3 BP-12 Exchange Loads

REP exchange loads are defined as the sum of a utility's qualifying residential and small farm consumer loads as determined in accordance with the utility's Residential Purchase and Sales Agreement (RPSA).

Utilities intending to participate in the REP for FY 2012-2013 were required to submit with their ASC filings a forecast of their residential and small farm sales, measured at the retail meter, for FY 2012-2017. The forecast REP exchange loads for FY 2012-2013 are increased to reflect the distribution losses submitted by the utilities with their initial ASC filings in June of 2010. Participating utilities' total REP exchange load forecasts for FY 2012-2013 are summarized in Table 5.2 of the Documentation.

Under the proposed 2010 REP Settlement, participating IOUs may agree to different billing determinants for determining the REP exchange load used to calculate REP benefits, referred to as Contract Exchange Load. If the proposed REP Settlement is adopted, the IOUs' Contract Exchange Loads will be determined in the BP-12 ratemaking process pursuant to the terms of the REP Settlement and published in GRSP II.N.

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Power Rates Tables

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Table 1: Proxy RHWMs for FY 2012 – 2013

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	Proxy RHWM aMW
	Existing Publics:	
1	Albion, City of	0.385
2	Alder Mutual Light Company	0.558
3	Ashland, City of	21.449
4	Asotin County PUD	0.586
5	Bandon, City of	7.558
6	Benton County PUD	195.203
7	Benton Rural Electric Association	65.027
8	Big Bend Electric Cooperative, Inc.	62.118
9	Blachly-Lane Electric Cooperative	17.332
10	Blaine, City of	8.712
11	Bonners Ferry, City of	5.811
12	Burley, City of	13.518
13	Canby Utility	20.489
14	Cascade Locks, City of	2.660
15	Central Electric Cooperative, Inc.	83.520
16	Central Lincoln People’s Utility District	153.537
17	Centralia, City of	25.970
18	Cheney, City of	15.719
19	Chewelah, City of	2.973
20	Clallam County PUD No. 1	83.733
21	Clark Public Utilities	327.363
22	Clatskanie People’s Utility District	99.002
23	Clearwater Power Company	24.277
24	Columbia Basin Electric Cooperative, Inc.	12.368
25	Columbia Power Cooperative Association	3.325

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	Proxy RHWM aMW
	Existing Publics:	
26	Columbia River People's Utility District	59.740
27	Columbia Rural Electric Cooperative, Inc.	36.861
28	Consolidated Irrigation District #19	0.230
29	Consumers Power, Inc.	46.945
30	Coos-Curry Electric Cooperative, Inc.	40.804
31	Coulee Dam, Town of	2.258
32	Cowlitz County PUD	533.882
33	Declo, City of	0.365
34	DOE National Energy Technology Laboratory	0.420
35	DOE Richland	23.275
36	Douglas Electric Cooperative, Inc.	19.336
37	Drain, City of	2.439
38	East End Mutual Electric Co., Ltd.	2.615
39	Eatonville, Town of	3.312
40	Ellensburg, City of	24.409
41	Elmhurst Mutual Power & Light Company	32.680
42	Emerald People's Utility District	52.208
43	Energy Northwest	3.563
44	Eugene Water and Electric Board	251.990
45	Fairchild Air Force Base	7.401
46	Fall River Rural Electric Cooperative, Inc.	34.272
47	Farmers Electric Company	0.530
48	Ferry County PUD No. 1	11.057
49	Flathead Electric Cooperative, Inc.	168.351
50	Forest Grove, City of	26.819
51	Franklin County PUD No. 1	115.639

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	**Proxy RHWM aMW**
	Existing Publics:	
52	Glacier Electric Cooperative, Inc.	21.217
53	Grant County PUD No. 2 - Grand Coulee	5.093
54	Grays Harbor County PUD No. 1	138.173
55	Harney Electric Cooperative, Inc.	23.370
56	Hermiston, City of	12.628
57	Heyburn, City of	4.640
58	Hood River Electric Cooperative	12.420
59	Idaho County Light & Power Cooperative	6.274
60	Idaho Falls Power	79.239
61	Inland Power & Light Company	106.927
62	Kittitas County PUD No. 1	8.488
63	Klickitat County PUD	35.613
64	Kootenai Electric Cooperative, Inc.	51.992
65	Lakeview Light & Power	33.457
66	Lane Electric Cooperative, Inc.	28.319
67	Lewis County PUD No. 1	110.859
68	Lincoln Electric Cooperative, Inc.	14.215
69	Lost River Electric Cooperative, Inc.	9.289
70	Lower Valley Energy	84.655
71	Mason County PUD No. 1	9.330
72	Mason County PUD No. 3	84.553
73	McCleary, City of	4.623
74	McMinnville Water and Light	99.781
75	Midstate Electric Cooperative, Inc.	47.929
76	Milton-Freewater, City of	10.716
77	Milton, City of	7.430

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	Proxy RHWM aMW
	Existing Publics:	
78	Minidoka, City of	0.103
79	Mission Valley Power	38.752
80	Missoula Electric Cooperative, Inc.	26.394
81	Modern Electric Water Company	26.968
82	Monmouth, City of	8.004
83	Nespelem Valley Electric Cooperative, Inc.	5.877
84	Northern Lights, Inc.	39.239
85	Northern Wasco County PUD	62.063
86	Ohop Mutual Light Company	10.202
87	Okanogan County Electric Coop, Inc	7.029
88	Okanogan County PUD No. 1	52.381
89	Orcas Power and Light Cooperative	26.810
90	Oregon Trail Electric Consumers Cooperative, Inc.	79.265
91	Pacific County PUD No. 2	37.174
92	Parkland Light and Water Company	14.648
93	Pend Oreille County PUD No. 1	19.012
94	Peninsula Light Company, Inc.	71.600
95	Plummer, City of	4.211
96	Port Angeles, City of	85.587
97	Port of Seattle	17.828
98	Raft River Rural Electric Cooperative, Inc.	33.725
99	Ravalli County Electric Cooperative, Inc.	18.283
100	Richland, City of	102.793
101	Riverside Electric Company	2.392
102	Rupert, City of	9.074

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	**Proxy RHWM aMW**
	Existing Publics:	
103	Salem Electric	38.405
104	Salmon River Electric Cooperative	30.444
105	Seattle City Light	507.966
106	Skamania County PUD No. 1	15.542
107	Snohomish County PUD No. 1	806.115
108	Soda Springs, City of	3.248
109	South Side Electric, Inc.	6.638
110	Springfield Utility Board	99.570
111	Steilacoom, Town of	4.861
112	Sumas, City of	3.868
113	Surprise Valley Electric Corp.	16.888
114	Tacoma Public Utilities	389.796
115	Tanner Electric Cooperative	12.549
116	Tillamook People's Utility District	52.078
117	Troy, City of	2.063
118	U.S. Dept of the Navy - Bremerton	29.773
119	U.S. Dept of the Navy - Everett	1.474
120	U.S. Dept. of the Navy - Bangor	20.578
121	Umatilla Electric Cooperative	107.759
122	Umpqua Indian Utility Cooperative	2.542
123	United Electric Cooperative, Inc.	28.505
124	US BIA – Wapato	1.798
125	Vera Water & Power	27.872
126	Vigilante Electric Cooperative, Inc.	19.403
127	Wahkiakum County PUD No. 1	4.993
128	Wasco Electric Cooperative, Inc.	14.094

Proxy RHWMs for FY 2012-2013		
A	B	C
	Preference Customer	Proxy RHWM aMW
	Existing Publics:	
129	Weiser, City of	6.097
130	Wells Rural Electric Company	98.342
131	West Oregon Electric Cooperative, Inc.	8.491
132	Whtcom County PUD No. 1	26.740
133	Yakama Power	4.268
	Total:	**6,998**
	New Publics	
134	Jefferson County PUD No. 1	33.319

Table 2: Revenue at Current Rates (Summary)

	B C D E	F	G	H	I	J	K
1	**Revenues at Current Rates**	**2011**	**2011**	**2012**	**2012**	**2013**	**2013**
2	**Category**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3	PF Full Service	$521,326	2,088	$840,558	3,471	$848,143	3,197
4	PF Partial Service	$372,700	1,461	$0	-	$0	-
5	PF Block Service	$433,915	1,762	$418,767	1,989	$419,207	1,657
6	PF Slice	$528,168	2,168	$636,495	1,891	$636,495	1,891
7	Irrigation Mitigation	$22,880	198	($13,172)	-	($13,172)	-
8	Low Density Discount	$0	-	($27,923)	-	($29,177)	-
9	PF customers (Subscription) sub-total	**$1,878,990**	**7,677**	**$1,854,725**	**7,351**	**$1,861,497**	**6,746**
10	DSIs sub-total	$103,066	340	$103,357	340	$103,083	340
11	FPS sub-total	$24,525	149	$1,716	8	$1,778	8
12	Short-term market sales sub-total	$351,757	1,227	$489,736	1,774	$531,754	1,674
13	Long Term Contractual Obligations sub-total	$89,540	93	$30,317	65	$29,865	62
14	Canadian Entitlement Return	$0	534	$0	522	$0	505
15	Renewable Energy Certificates sub-total	$4,855	59	$3,722	40	$3,722	40
16	Other Sales sub-total	$10,644	-	$5,506	-	$5,498	-
17	**Gross Sales**	**$2,463,377**	**10,080**	**$2,489,078**	**10,100**	**$2,537,196**	**9,375**
18	**Miscellaneous Revenues**	**$25,315**	**152**	**$25,315**	**177**	**$25,315**	**177**
19	**Generation Inputs / Inter-business line**	**$97,842**	**14**	**$123,374**	**9**	**$135,390**	**9**
20	4(h)(10)(c)	$112,941	-	$94,386	-	$98,466	-
21	Colville and Spokane Settlements	$4,600	-	$4,600	-	$4,600	-
22	**Treasury Credits**	**$117,541**	**-**	**$98,986**	**-**	**$103,066**	**-**
23	Augmentation Power Purchase total	$1,994	8	$120,878	329	$187,598	454
24	Balancing Power Purchase sub-total	$112,243	1,325	$23,713	106	$14,568	69
25	Other Power Purchase total	$46,277	83	$53,356	84	$68,282	83
26	**Power Purchases**	**$160,514**	**1,416**	**$197,947**	**518**	**$270,447**	**606**

Table 3: Revenue at Proposed Rates (Summary)

	B C D E	F	G	H	I	J	K
1	**Revenues at Proposed Rates**	**2011**	**2011**	**2012**	**2012**	**2013**	**2013**
2	**Category**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3	PF customers (Subscription) sub-total	**$1,878,990**	**7,677**	**-**	**-**	**-**	**-**
4	Composite Revenue	-		$2,367,774		$2,372,898	
5	Non-Slice Revenue	-		($389,063)		($390,222)	
6	Load Shaping Revenue	-		$22,584		$25,913	
7	Demand Revenue	-		$56,766		$56,078	
8	Irrig. Mit.	-		($22,751)		($22,751)	
9	Low Density Discount	-		($34,674)		($37,094)	
10	Tier 2	-		$8,574		$24,114	
11	RSS (Non-Federal)	-		$370		$377	
12	PF customers (CHWM) sub-total	**-**		**$2,009,582**	**7,032**	**$2,029,313**	**7,088**
13	DSIs sub-total	$103,066	340	$108,867	340	$108,590	340
14	Pre-Subscription (FPS) sub-total	$24,525	149	$1,716	8	$1,778	8
15	Short-term market sales sub-total	$349,783	1,227	$489,736	1,774	$531,754	1,674
16	Long Term Contractual Obligations sub-total	$89,540	93	$30,317	65	$29,865	62
17	Canadian Entitlement Return	$0	534	$0	522	$0	505
18	Renewable Energy Certificates sub-total	$4,855	59	$3,722	40	$3,722	40
19	Other Sales sub-total	$10,644	-	$5,506	-	$5,498	-
20	**Gross Sales**	**$2,461,403**	**10,080**	**$2,649,446**	**9,780**	**$2,710,519**	**9,718**
21	**Miscellaneous Revenues**	**$25,315**	**152**	**$25,315**	**177**	**$25,315**	**177**
22	**Generation Inputs / Inter-business line**	**$97,842**	**14**	**$123,374**	**9**	**$135,390**	**9**
23	4(h)(10)(c)	$112,941		$94,386		$98,466	
24	Colville and Spokane Settlements	$4,600		$4,600		$4,600	
25	**Treasury Credits**	**$117,541**	**-**	**$98,986**	**-**	**$103,066**	**-**
26	Augmentation Power Purchase sub-total	$1,994	8	$120,878	329	$187,598	454
27	Balancing Power Purchase sub-total	$112,243	1,325	$23,713	106	$14,568	69
28	Other Power Purchase sub-total	$46,277	83	$53,356	84	$68,282	83
29	**Power Purchases**	**$160,514**	**1,416**	**$197,947**	**518**	**$270,447**	**606**

Table 4: Adjustments to Financial Reserves Base Amount

Unit	Account	Stat Amt	Ref	Line Descr	Reason for adjustment
POWER	999044	$ (673,094.63)	AR00114197	Receipt from DOJ	1
POWER	999044	$ (104,552.35)	AR00117261	Receipt from FERC	1
POWER	999044	$ (53,497.33)	AR00119524	Receipt from DOJ	1
POWER	999044	$ (2,789.38)	AR00122086	Receipt from DOJ	1
POWER	999044	$ (5.04)	AR00129431	Stock dividend	2
POWER	999044	$ 39,274.42	OA04101016	CAISO balance adjustment	4
POWER	999044	$ (6,667.74)	AR00127956	Receipt from FERC	1
POWER	999044	$ (1,528.11)	AR00128358	Receipt from DOJ	1
		$ (802,860.16)			

Reasons for adjustments

1) BPA's receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002,
2) BPA's receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002,
3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002, and
4) BPA's write-off of bad debt expense pertaining to power marketing transactions that occurred before FY 2002.

Base amount of financial reserves =	$495,600,000
Adjustment to the base amount of financial reserves =	$495,600,000 + $802,860
Resulting amount of financial reserves =	**$496,402,860**

Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount.
Adjustment amounts, if positve, are subtracted from the base amount of financial reserves, thereby decreasing the size of the base amount.

Appendix A

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Appendix A

7(c)(2) Industrial Margin Study

1. INTRODUCTION

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to 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. PURPOSE

The purpose of this study is to describe Staff'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-12 energy charges. These adjusted PF-12 energy charges and Demand Charges are applied to the DSI billing determinants to determine the IP-12 rate.

3. METHODOLOGY

3.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

The PF-12 demand and energy charges (before any 7(b)(2) or floor rate adjustments) are applied to the forecast DSI billing determinants.

3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

3.3 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. 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.

4. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves two 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 margin. The BPA DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

4.1 Data Base

The data base was collected 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 were required to sign confidentiality agreements at the PPC offices. All utility data reported has been identified by a randomly assigned number. This is essentiality the same way margin data was displayed in the 2002 and 2007 industrial margin studies. The data base consists of cost information from 33 utilities that have at least 1 industrial customer with a peak load of at least 3.5 MW. Attachment A displays each participating utility’s total energy used by large industrial consumers, it’s individual industrial margin, it’s weighted individual margin, and the overall energy-weighted typical industrial margin for all utilities in the 2012 margin study.

4.2 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. The data for each of the utilities in the study are included as Attachment B. Various costs assigned to the "other" category are added to arrive at each utility's industrial margin.

4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The 2012 weighted industrial margin is 0.68 mills/kWh.

Summary - 2012 Margin Study Results

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Taxes	Weighted Margin
1	51,410,428					$ 5.67		0.01674
2	1,581,923,558					$ 0.04		0.00386
3	95,688,000	$ 47.66	$ 36.62	$ -	$ 9.38	$ 0.45	$ 1.21	0.00249
5	42,823,202	$ 57.46	$ 36.78	$ 0.85	$ 18.61	$ 0.42	$ 0.80	0.00104
6	29,114,880	$ 43.02	$ 34.50	$ 2.36	$ 2.87	$ 0.72	$ 2.57	0.00121
7	40,694,000					$ -		0.00000
8	405,668,000					$ -		0.00000
9	361,407,000	$ 4.78	$ 3.84	$ 0.01	$ 0.72	$ 0.07	$ 0.13	0.00151
11	467,121,000	$ 45.11	$ 32.63	$ 5.45	$ 3.18	$ 0.81	$ 3.04	0.02162
12	248,035,470	$ 36.22	$ 34.20	$ 0.25	$ 1.36	$ 0.00	$ 0.38	0.00002
13	119,932,734	$ 38.94	$ 36.80	$ -	$ 0.04	$ 0.01	$ 2.09	0.00008
14	61,910,899	$ 10.77	$ -	$ 0.47	$ 9.79	$ 0.51	$ -	0.00181
15	966,012,620					$ 0.02		0.00101
16	169,040,000					$ 0.47		0.00452
17	352,800,436	$ 41.45	$ 30.46	$ 0.23	$ 10.69	$ 0.06	$ -	0.00120
18	5,390,158,000	$ 49.42	$ 40.45	$ 0.90	$ 6.60	$ 0.88	$ 0.58	0.27346
20	297,405,000					$ 0.15		0.00261
21	340,000,000					$ 0.43		0.00842
23	78,758,000	$ 43.69	$ 33.49	$ 0.12	$ 8.23	$ 1.11	$ 0.74	0.00500
24	203,423,478	$ 62.26	$ 33.19	$ 4.05	$ 22.70	$ 0.10	$ 2.22	0.00118
25	152,608,000	$ 40.67	$ 31.32	$ 0.77	$ 4.29	$ 3.40	$ 0.89	0.02977
26	47,700,000	$ 46.82	$ 34.17	$ 0.85	$ 10.86	$ 0.32	$ 0.62	0.00088
27	15,897,484					$ 0.32		0.00029
28	3,022,602,000					$ 0.54		0.09302
29	718,303,000					$ 0.35		0.01463
30	808,561,000	$ 51.24	$ 47.77	$ 0.14	$ 0.30	$ 0.04	$ 2.99	0.00183
31	223,878,000	$ 36.86	$ 29.79	$ -	$ 5.86	$ 0.71	$ 0.49	0.00917
32	750,395,000	$ 54.12	$ 44.55	$ 2.13	$ 0.15	$ 4.19	$ 3.10	0.18042
33	194,837,000	$ 46.71	$ 39.37	$ -	$ 4.53	$ 0.01	$ 2.81	0.00009
34	21,884,198					$ 5.29		0.00665
35	94,165,000	$ 26.69	$ 7.06	$ 0.66	$ 15.48	$ 0.03	$ 3.47	0.00016
36	19,516,800					$ 0.03		0.00004
37	38,909,777					$ 0.01		0.00001
Total:	**17,412,583,964**							**0.68474**

Utility Number: # 1

Two industrial customers; rates set through contract.

Customer 1: BPA rate plus $1.09/MWh; 2009 sales (kWh)	=		**31,485,920**
Margin	=		**$ 34,320**
Customer 2: BPA rate plus $21,430/mo; 2009 sales	=		**19,924,508**
Margin	=		**$ 257,160**
Total margin from Customers 1 & 2	=	**$ 291,480**	
Sales to Customers 1 & 2 (kWh)	=	**51,410,428**	

Utility Number: # 2

Large Industrial includes sales under Schedules 14, 15, & 16

	Ave # of customers	Load (kWh)	Monthly basic charge
Schedule 14	3	123,852,000	$ 200
Schedule 15	6	1,223,870,998	$ 500
Schedule 16	10	234,200,560	$ 200
		1,581,923,558	
		Total basic charges/year =	**$ 67,200**

Utility Number: # 3							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 3,503,816	$ 3,503,816					$ 3,503,816
Transmission:	$ -						
Distribution:	$ 66,980			$ 66,980			$ 66,980
Customer Accounts:	$ 20,315				$ 20,315		$ 20,315
Customer Services:	$ 4,599				$ 4,599		$ 4,599
Admin & Genl:	$ 68,093			$ 49,632	$ 18,461		$ 68,093
Taxes:	$ 115,384					$ 115,384	$ 115,384
Depreciation:	$ 779,001			$ 779,001			$ 779,001
Interest:	$ 2,352			$ 2,352			$ 2,352
TOTAL	$ 4,560,540	$ 3,503,816		$ 897,965	$ 43,375	$ 115,384	$ 4,560,540

Utility Number: # 5							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 1,574,999	$ 1,574,999					$ 1,574,999
Transmission:	$ 14,196		$ 14,196				$ 14,196
Distribution:	$ 310,053			$ 310,053			$ 310,053
Customer Accounts:	$ 7,316				$ 7,316		$ 7,316
Meter Reading:	$ 194			$ 194.00			$ 194
Customer Service:	$ 3,456				$ 3,456		$ 3,456
Sales Exp:	$ 2,549				$ 2,549		$ 2,549
Admin & Genl (1):	$ 120,230		$ 5,056	$ 110,429	$ 4,744		$ 120,230
Depreciation:	$ 232,235		$ 10,168	$ 222,067			$ 232,235
Taxes:	$ 34,108					$ 34,108	$ 34,108
Interest:	$ 159,676		$ 6,991	$ 152,685			$ 159,676
Other:	$ 1,731		$ 76	$ 1,655			$ 1,731
TOTAL	$ 2,460,743	$ 1,574,999	$ 36,486	$ 797,084	$ 18,065	$ 34,108	$ 2,460,743

Utility Number: # 6	Large Industrial		Production		Transmission		Distribution		Other		Taxes		Sum	
Purchased Power:	$	1,035,622	$	1,035,622									$	1,035,622
Transmission:	$	712			$	712	$	-					$	712
Distribution:	$	59,107					$	59,107					$	59,107
Meter Reading:	$	18					$	18					$	18
Customer Records & Collection:	$	54					$	54					$	54
Misc Customer Service:	$	87							$	87			$	87
A & G:	$	41,855			$	497	$	41,297	$	61			$	41,855
Taxes:	$	74,851									$	74,851	$	74,851
Inrerest:	$	46,721			$	555	$	46,166					$	46,721
Capital Projects:	$	88,598			$	67,619			$	20,979			$	88,598
Other Deduction (2):	$	(63,872)			$	(758)	$	(63,021)	$	(93)			$	(63,872)
BPA Conservation, Con Aug, other:	$	(31,231)	$	(31,231)									$	(31,231)
TOTAL	$	1,252,522	$	1,004,391	$	68,625	$	83,621	$	21,034	$	74,851	$	1,252,522

Utility Number: # 7
One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 40,694 MWh
Monthly Base Charge = $0.00
Demand Charge = $5.75/kW
Energy Charge = $0.0316/kWh

Utility Number: # 8

One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 405,668 MWh

Monthly Base Charge = $0.00

Industrial rates set by city ordinance

Utility Number: # 9

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Costs:	$ 1,387,888	$ 1,387,888					$ 1,387,888
Transmission:	$ 1,320		$ 1,320				$ 1,320
Distribution:	$ 71,299			$ 71,299			$ 71,299
Customer Accounts:	$ 263				$ 263		$ 263
Public Relations & Info:	$ 11,873				$ 11,873		$ 11,873
Energy Services:	$ 3,159				$ 3,159		$ 3,159
Admin & Genl:	$ 63,036		$ 946	$ 51,079	$ 11,011		$ 63,036
Depreciation:	$ 75,872		$ 1,379	$ 74,493			$ 75,872
Taxes:	$ 48,396					$ 48,396	$ 48,396
Interest:	$ 65,238		$ 1,186	$ 64,052			$ 65,238
TOTAL	$ 1,728,344	$ 1,387,888	$ 4,831	$ 260,923	$ 26,306	$ 48,396	$ 1,728,344

Utility Number: # 11	Two Industrial Customers	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 15,244,327	$ 15,244,327					$ 15,244,327
Transmission:	$ 2,544,405		$ 2,544,405				$ 2,544,405
Distribution:	$ 1,481,945			$ 1,481,945			$ 1,481,945
Meter Reading + Cust Records:	$ 5,366			$ 5,366			$ 5,366
Customer Education:	$ 77,324				$ 77,324		$ 77,324
Low Income Assist.:	$ 156,540				$ 156,540		$ 156,540
Electirc Marketing:	$ 142,594				$ 142,594		$ 142,594
Taxes:	$ 1,419,465					$ 1,419,465	$ 1,419,465
TOTAL	$ 21,071,966	$ 15,244,327	$ 2,544,405	$ 1,487,311	$ 376,458	$ 1,419,465	$ 21,071,966

Utility Number: # 12	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 644,417	$ 644,417					$ 644,417
Purchased Power:	$ 8,379,469	$ 8,379,469					$ 8,379,469
Transmission:	$ 77,781		$ 77,781				$ 77,781
Distribution:	$ 412,110			$ 412,110			$ 412,110
Meter Reading + Customer Records:	$ 9,303			$ 9,303			$ 9,303
Customer Service:	$ 3,113				$ 3,113		$ 3,113
Admin & Genl:	$ 496,109	$ 278,795	$ 33,651	$ 182,317	$ 1,347		$ 496,109
Taxes:	$ 95,106					$ 95,106	$ 95,106
Interest:	$ 341,788	$ 192,595	$ 23,246	$ 125,947			$ 341,788
Capital Projects:	$ 455,818	$ 256,850	$ 31,002	$ 167,966			$ 455,818
Other Revenue:	$ (1,931,751)	$ (1,270,440)	$ (103,488)	$ (560,694)	$ (4,142)		$ (1,938,764)
TOTAL	$ 8,983,263	$ 8,481,687	$ 62,191	$ 336,948	$ 318	$ 95,106	$ 8,976,250

Utility Number: # 13

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 3,813,592	$ 3,813,592					$ 3,813,592
Transmission							
Distribution							
Conservation	$ 600,000	$ 600,000					$ 600,000
Meters & Services	$ 4,742			$ 4,742			$ 4,742
Accounting	$ 536				$ 536		$ 536
Customer Related	$ 789				$ 789		$ 789
Revenue Related	$ 250,374					$ 250,374	$ 250,374
TOTAL	$ 4,670,033	$ 4,413,592		$ 4,742	$ 1,325	$ 250,374	$ 4,670,033

Utility Number # 14							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ -						
Transmission:	$ 29,120		$ 29,120				$ 29,120
Distribution:	$ 560,614			$ 560,614			$ 560,614
Metering & Billing:	$ 45,398			$ 45,398			$ 45,398
Customer Services:	$ 31,565				$ 31,565		$ 31,565
TOTAL	$ 666,697		$ 29,120	$ 606,012	$ 31,565		$ 666,697

Utility Number: # 15	
7 customers in High Voltage General rate class; load = 966,012,620 kWh	
Customer Charge per meter per month =	**$ 210**
Total customer charges per year =	**$ 17,640**

Utility Number: # 16	
1 large industrial customer with peak of at least 3.5 aMW	
Total Insustrial sales in 2009 = 169,040 MWh	
Fixed charge (equivalent to customer charge of $6,557/month; annual cost =	$ 78,684

Utility Number: # 17							
	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 10,747,941	$ 10,747,941					$ 10,747,941
Transmission:	$ 15,940		$ 15,940				$ 15,940
Distribution:	$ 735,733			$ 735,733			$ 735,733
Customer Accnts:	$ 4,917				$ 4,917		$ 4,917
Customer Svcs:	$ 1,963				$ 1,963		$ 1,963
Interest on Debt (2):	$ 398,427		$ 8,449	$ 389,978			$ 398,427
Depreciation (2):	$ 551,528		$ 11,696	$ 539,832			$ 551,528
Additional revenue req.:	$ 2,165,398		$ 45,621	$ 2,105,704	$ 14,073		$ 2,165,398
TOTAL	$ 14,621,847	$ 10,747,941	$ 81,706	$ 3,771,247	$ 20,953		$ 14,621,847

Utility Number: # 18

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 45,179,704	$ 45,179,704					$ 45,179,704
Purchased Power:	$ 182,460,007	$ 182,460,007					$ 182,460,007
Conservation:	$ 26,968,662	$ 26,968,662					$ 26,968,662
Transmission:	$ 9,881,306		$ 9,881,306				$ 9,881,306
Distribution:	$ 72,213,558			$ 72,213,558			$ 72,213,558
Customer costs:	$ 4,980,734				$ 4,980,734		$ 4,980,734
Low income assistance:	$ 4,680,598				$ 4,680,598		$ 4,680,598
Franchise Adjustments:	$ 3,136,376					$ 3,136,376	$ 3,136,376
Revenue Credits:	$ (83,124,365)	$ (36,590,117)	$ (5,011,314)	$ (36,623,179)	$ (4,899,754)		$ (83,124,365)
TOTAL	$ 266,376,580	$ 218,018,256	$ 4,869,992	$ 35,590,379	$ 4,761,578	$ 3,136,376	$ 266,376,580

Utility Number: # 20

2 large industrial customers with peak of at least 3.5 aMW

Total Industrial sales in 2009 = 297,405 MWh

Margin charges = 0.0195 cents/kWh for first 19.1 aMW in a month, and 0.0098 cents for each kWh thereafter

167,316,000	kWh at 0.0195 cents
130,089,000	kWh at 0.0098 cents

Total margin charges for 2009 = **4,537,534** cents = **$ 45,375**

Utility Number: # 21

Industrial sales in 2010 = 340,000 MWh

Industrial customers in 2010 = 35

Customer cost per month in 2010 = **$349**

Total customer cost = **$146,639**

Utility Number: # 23	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 2,626,334	$ 2,626,334					$ 2,626,334
Transmission:							
Distribution:	$ 318,070			$ 318,070			$ 318,070
Customer Services & Accts:	$ 63,752			$ 9,575	$ 54,177		$ 63,752
A & G:	$ 155,355	$ 11,293		$ 130,111	$ 13,951		$ 155,355
Depreciation:	$ 141,272		$ 9,761	$ 112,513	$ 18,998		$ 141,272
Interest:	$ 77,847			$ 77,847			$ 77,847
Taxes:	$ 58,569					$ 58,569	$ 58,569
TOTAL	$3,441,199	$2,637,627	$9,761	$648,116	$87,126	$58,569	$3,441,199

Utility Number: # 24

	(includes NLSL)	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 6,752,558	$ 6,752,558					$ 6,752,558
Transmission:	$ 414,702		$ 414,702				$ 414,702
Distribution:	$ 2,326,532			$ 2,326,532			$ 2,326,532
Customer Related:	$ 19,242				$ 19,242		$ 19,242
A & G:	$ 448,614		$ 67,395	$ 378,092	$ 3,127		$ 448,614
Depr & Amort:	$ 939,205		$ 142,086	$ 797,119			$ 939,205
Taxes:	$ 451,195					$ 451,195	$ 451,195
Interest:	$ 1,347,794		$ 203,898	$ 1,143,896			$ 1,347,794
Capital Requirements:	$ 232,129		$ 35,117	$ 197,011			$ 232,129
Other Income:	$ (267,290)		$ (40,154)	$ (225,272)	$ (1,863)		$ (267,290)
TOTAL	$ 12,664,681	$ 6,752,558	$ 823,043	$ 4,617,379	$ 20,506	$ 451,195	$ 12,664,681

Utility Number: # 25

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 4,780,364	$ 4,780,364					$ 4,780,364
Transmission:	$ 69,374		$ 69,374				$ 69,374
Distribution:	$ 393,197			$ 393,197			$ 393,197
Customer Related:	$ 1,729				$ 1,729		$ 1,729
A & G:							
Prop ins/inj & damag:	$ 17,112			$ 17,112			$ 17,112
Cust acct/serv & info/sales rel:	$ 480,913				$ 480,913		$ 480,913
Depreciation:	$ 328,871	$ 18	$ 48,211	$ 244,836	$ 35,806		$ 328,871
Taxes:	$ 135,572					$ 135,572	$ 135,572
TOTAL	$ 6,207,132	$ 4,780,382	$ 117,585	$ 655,145	$ 518,448	$ 135,572	$ 6,207,132

Utility Number: # 26	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 1,629,832	$ 1,629,832					$ 1,629,832
Transmission:	$ 12,295		$ 12,295				$ 12,295
Distribution:	$ 150,666			$ 150,666			$ 150,666
Customer Related:							
Meter reading & cust. Records:	$ 6,440			$ 6,440			$ 6,440
Customer sales & service:	$ 7,343				$ 7,343		$ 7,343
Depreciation:	$ 129,443		$ 9,395	$ 120,048			$ 129,443
A & G + Other Expense:	$ 185,637		$ 12,914	$ 165,011	$ 7,712		$ 185,637
Taxes:	$ 29,545					$ 29,545	$ 29,545
Interest:	$ 74,929		$ 5,438	$ 69,491			$ 74,929
Other Expenses:	$ 7,009		$ 506	$ 6,200	$ 302		$ 7,008
TOTAL	$2,233,139	$1,629,832	$40,548	$517,856	$15,357	$29,545	$2,233,138

Utility Number: # 27

Utility # 27 has 1 large industrial customer; 2009 load = **15,897,484** kWh

Customer cost per month in 2010 = **$ 418.70**

Total customer cost = $ 5,024.40

Utility Number: # 28

Utility # 28 has 3 large industrial customers; 2009 load = 3,022,602,000 kWh
Margin charges set in contract with each customer; total margin charges in 2009 = $1,619,690

Utility Number: # 29

1 large industrial customer; 2009 load = 718,303 MWh

Direct costs of contract administration for this customer (2 plants)	=	$	175,442
		$	79,376
		$	**254,818**

Utility Number: # 30

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 42,669,341	$ 42,669,341					$ 42,669,341
Transmission:	$ -		$ -				$ -
Distribution:	$ 322,009			$ 322,009			$ 322,009
Meter reading + customer records:	$ 2,429			$ 2,429			$ 2,429
Customer related:	$ 1,301				$ 1,301		$ 1,301
A & G:	$ 260,302			$ 259,262	$ 1,040		$ 260,302
Taxes:	$ 2,418,041					$ 2,418,041	$ 2,418,041
Interest:	$ 673,382			$ 673,382			$ 673,382
Capital Projects:	$ 290,096		$ 110,346	$ 145,596	$ 34,154		$ 290,096
Other Revenues:	$ (5,209,277)	$ (4,047,303)		$ (1,157,333)	$ (4,641)		$ (5,209,277)
TOTAL	$ 41,427,624	$ 38,622,038	$ 110,346	$ 245,345	$ 31,854	$ 2,418,041	$ 41,427,624

Utility Number: # 31

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production	$ 6,669,764	$ 6,669,764					$ 6,669,764
Transmission							
Fixed Oper Costs (Distn)	$ 406,590			$ 406,590			$ 406,590
on Oper Exp (Cust Svc & Acct)	$ 71,114				$ 71,114		$ 71,114
Admin & Bus Exp	$ 530,588			$ 442,017	$ 88,571		$ 530,588
Taxes	$ 110,812					$ 110,812	$ 110,812
LTGO Debt Servd & Cap	$ 462,840			$ 462,840			$ 462,840
TOTAL	$ 8,251,708	$ 6,669,764	$ -	$ 1,311,447	$ 159,685	$ 110,812	$ 8,251,708

Utility Number: # 32	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 33,760,238	$ 33,760,238					$ 33,760,238
Transmission:	$ 145,001		$ 145,001				$ 145,001
Distribution:	$ 10,066			$ 10,066			$ 10,066
Customer Services & Accounts:	$ 2,171,387				$ 2,171,387		$ 2,171,387
A & G:	$ 989,157		$ 61,651	$ 4,280	$ 923,226		$ 989,157
Capital Projects:	$ 1,151,312		$ 1,076,576	$ 74,736			$ 1,151,312
Debt Service:	$ 333,697		$ 312,035	$ 21,662			$ 333,697
Direct Assignments:	$ 1,442,631		$ 89,915	$ 6,242	$ 1,346,474		$ 1,442,631
Other Revenue:	$ (1,721,861)	$ (329,663)	$ (86,749)	$ (6,022)	$ (1,299,426)		$ (1,721,860)
Taxes:	$ 2,329,920					$ 2,329,920	$ 2,329,920
TOTAL	$ 40,611,548	$ 33,430,575	$ 1,598,429	$ 110,963	$ 3,141,661	$ 2,329,920	$ 40,611,549

Utility Number: # 33							
	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 7,378,831	$ 7,378,831					$ 7,378,831
Conservation:	$ 134,032	$ 134,032					$ 134,032
Distribution:	$ 161,203			$ 161,203			$ 161,203
Customer Related:	$ 714				$ 714		$ 714
A & G:	$ 398,772	$ 180,599		$ 217,211	$ 962		$ 398,772
Broad Band:	$ 93,962	$ 42,554		$ 51,181	$ 227		$ 93,962
Interest:	$ 531,746			$ 531,746			$ 531,746
Cash Flow:	$ 495,596	$ 224,450		$ 269,950	$ 1,196		$ 495,596
Taxes:	$ 547,357					$ 547,357	$ 547,357
Other Revenue:	$ (640,934)	$ (290,272)		$ (349,116)	$ (1,546)		$ (640,934)
TOTAL	$ 9,101,279	$ 7,670,195	$ -	$ 882,175	$ 1,552	$ 547,357	$ 9,101,279

Utility Number: # 34

1 large industrial customer with peak of at least 3.5 aMW

2008 Industrial load = 21,884,198 kWh

Margin = $.00529/kWh

Total margin charges for 2008 = **$ 115,767**

Utility Number: # 35	Total Utility	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Production:	$ 2,477,820	$ 318,447	$ 318,447					$ 318,447
Transmission:	$ 428,864	$ 55,117		$ 55,117				$ 55,117
Distribution:	$ 4,226,132	$ 543,138			$ 543,138			$ 543,138
Metering Reading:	$ 571,769	$ 73,483			$ 73,483			$ 73,483
Credit & Billing:	$ 853,653	$ 109,711			$ 109,711			$ 109,711
Information & Advertising:	$ 52,530	$ 6,751				$ 6,751		$ 6,751
Administrative & General Expenses:	$ 4,598,604	$ 591,008	$ 170,068	$ 29,435	$ 387,900	$ 3,605		$ 591,008
Taxes:	$ 2,541,360	$ 326,613					$ 326,613	$ 326,613
Debt Service:	$ 7,940,000	$ 1,020,441	$ 295,443	$ 51,135	$ 673,863			$ 1,020,441
Capital Projects:	$ 6,280,000	$ 807,100	$ 233,675	$ 40,445	$ 532,980			$ 807,100
Total Transfers:	$ 841,720	$ 108,177	$ 31,320	$ 5,421	$ 71,436			$ 108,177
Energy Sales:	$ (9,248,760)	$ (1,188,642)	$ (342,042)	$ (59,201)	$ (780,148)	$ (7,251)		$ (1,188,642)
Other Revenues:	$ (2,006,586)	$ (257,885)	$ (41,976)	$ (60,458)	$ (155,087)	$ (363)		$ (257,884)
TOTAL	$ 19,557,106	$ 2,513,460	$ 664,935	$ 61,895	$ 1,457,276	$ 2,742	$ 326,613	$ 2,513,461

Utility Number: # 36

1 large industrial customer; 2008 load = 19,516,800 kWh

Monthly Customer Charge = **$51.37** Total charges = **$ 616.44**

Utility Number: # 37

1 large industrial customer; 2010 load = 38,909,777 kWh

Customer charge = **$208**

BONNEVILLE POWER ADMINISTRATION

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