B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

2010 BPA Rate Case
Wholesale Power Rate Final Proposal

WHOLESALE POWER RATE DEVELOPMENT STUDY

July 2009

WP-10-FS-BPA-05

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2010 WHOLESALE POWER RATE DEVELOPMENT STUDY

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
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)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
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
PS	BPA Power Services
PSC	power sales contract
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
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
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
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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1. INTRODUCTION

1.1 Purpose of the Wholesale Power Rate Development Study

The Wholesale Power Rate Development Study (WPRDS) serves two primary purposes: (1) to explain the methodologies and processes used to develop the power rates that will be applied to BPA's wholesale power products and services; and (2) to demonstrate the revenues that the power rates will recover for the applicable rate period.

1.2 Rate Process Overview

The development of rates in the WPRDS uses inputs from a variety of sources. Loads and resources are provided to the WPRDS by the Loads and Resources Study, WP-10-FS-BPA-01, and its accompanying documentation, WP-10-FS-BPA-01A. Revenue requirement information is provided by the Revenue Requirement Study, WP-10-FS-BPA-02, and its accompanying documentation, WP-10-FS-BPA-02A and WP-10-FS-BPA-02B. The Market Price Forecast Study, WP-10-FS-BPA-03, and its accompanying documentation, WP-10-FS-BPA-03A, provide the WPRDS with information regarding electricity market prices used in the WPRDS for seasonal and diurnal differentiation of energy rates, as well as for informing the development of demand rates. The Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, and its accompanying documentation, WP-10-FS-BPA-04A and WP-10-FS-BPA-04B, provide short-term balancing purchases expenses, augmentation expenses, secondary energy sales and revenue, and Planned Net Revenues for Risk (PNRR). The Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06, with its documentation, WP-10-FS-BPA-06, provide the WPRDS the results of the section 7(b)(2) rate test. Explanation and documentation for generation inputs and other inter-business line cost allocations are included in the Generation Inputs Study, WP-10-FS-BPA-08. The results of the Generation Inputs Study are provided to the WPRDS as revenue credits. The results of the power rate development process, including rates for power products and services, plus general rate schedule provisions, appear in Appendix B to the Administrator's Record of Decision, WP-10-A-BPA-02-AP02. The revenues resulting from the rates developed herein are used by the Revenue Requirement Study in the Revised Revenue Test. Revenue Requirement Study, WP-10-FS-BPA-02, section 4.3.

1.3 Organization of the WPRDS

The WPRDS is divided into six sections. The first is this Introduction. Section 2 describes the criteria and methods applied in the development of power rate design, including Slice, and transmission services such as General Transfer Agreements. Section 3 describes the steps employed in calculating rates: cost of service analysis, rate design adjustments, and Slice product separation step. Section 4 describes the revenue forecasts that are used to test current and proposed rates for sufficiency to recover BPA's revenue requirement. Section 5 describes the rates and schedules developed in the WPRDS: Priority Firm Power (PF-10), New Resource Firm Power (NR-10), Industrial Firm Power (IP-10), and Firm Power Products and Services (FPS-10). Section 6 describes the development of Average System Costs (ASC), which occurs in the ASC Review Process separate from the WP-10 rate proceeding.

Details supporting the WPRDS inputs, assumptions, and calculations are included in the Documentation, WP-10-FS-BPA-05A. Excerpts of the final ASC Reports as approved by BPA's Administrator are included in the study Documentation, Chapter 5. The Documentation includes four appendices: Appendix A describes the 7(c)(2) Industrial Margin Study, and Appendices B, C, and D describe BPA's policy for the development of regional conservation and renewable resources.

2. RATE DESIGN

The rate design for the WP-10 wholesale power rates is based on the design of the FY 2009 rates. Each of the following sections describes the components of the various proposed rates. Section 2.1 discusses the monthly and diurnal differentiation of the PF Preference energy rates; the proposed FY 2010-2011 PF Preference energy rates are proportionally scaled from the FY 2009 rates. Section 2.2 describes the monthly and diurnal differentiation of the IP energy rates. Section 2.3 describes the monthly and diurnal differentiation of the NR energy rates. The IP and NR energy rates both are time differentiated based on the marginal cost of power. Section 2.4 discusses the design of rates for Demand, Factoring Service, and Load Variance. Section 2.5 describes Unauthorized Increase (UAI) Charges and Excess Factoring Charges. Section 2.6 discusses the design of the FPS rate. Section 2.7 discusses the Flexible PF and NR Rate Option. Section 2.8 discusses the PF Exchange rate, including the 7(b)(3) Supplemental Rate Charge. Section 2.9 describes the Irrigation Rate Mitigation Product. Section 2.10 describes the Low Density Discount. Section 2.11 discusses the Conservation and Renewables Program. Section 2.12 discusses the Green Energy Premium. Section 2.13 discusses the Targeted Adjustment Charge (TAC). Section 2.14 discusses the GTA Delivery Charge. Section 2.15 discusses the Slice of the System (Slice) product, the Slice revenue requirement, and the Slice rate.

2.1 Monthly and Diurnal Differentiation of PF Preference Energy Rates

Monthly and diurnal differentiation of the WP-10 PF Preference energy rates is established in the same manner as that used for the current FY 2009 rates, based on the WP-07 Supplemental Final Proposal. The rates are listed in Table 2.1, below.

Table 2.1
PF Preference Energy Rates
PF-07R for FY 2009, $/MWh

	A	B	C	D	E	F	G	H	I	J	K	L
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62
LLH	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.64	$14.17	$9.85	$16.73	$19.85	$22.17

PF-10 for FY 2010-2011, $/MWh

HLH	$31.41	$33.50	$34.96	$29.68	$30.31	$28.12	$26.39	$22.04	$19.95	$24.57	$28.78	$29.70
LLH	$23.01	$24.43	$25.65	$21.46	$21.68	$20.61	$18.97	$15.24	$10.59	$17.99	$21.34	$23.84

The FY 2010-2011 PF Preference energy rates are determined by adjusting the PF-07R rates in Table 2.1 up by an equal percentage such that the PF energy rates, in combination with the PF demand and PF load variance rates, will recover the amount of the total revenue requirement for the rate period allocated to the PF Preference non-Slice rate pool. Documentation, WP-10-FS-BPA-05A, Table 2.7.

2.2 IP Energy Rates

2.2.1 Adjustment to IP Energy Rates for Reserves Provided

For ratesetting purposes, BPA assumes 402 aMW of sales to the DSIs. The 402 aMW includes 385 aMW for sales to the two aluminum DSIs and 17 aMW to Port Townsend Paper. These power sales are also assumed to provide interruption reserve rights to BPA.

The starting point for valuing reserves provided by DSIs is $6.02 per kW per month for capacity, which is the unit cost for Operating Reserves (Supplemental only) as established in the Generation Inputs Study, WP-10-FS-BPA-08, section 5. The Operating Reserves documented in the Generation Inputs Study are provided by the Federal Columbia River Power System (FCRPS), and are available in any hour and on any day.

The reserves provided by DSIs are evaluated using the following criteria. The maximum amount Power Services may pay for incremental within-hour balancing reserve from a DSI is capped at the unit cost for Operating Reserve (Supplemental only) capacity that is provided as a generation input to Transmission Services.

The first step in valuing the DSI reserves is to determine the quantity of reserves provided. To do this, the total DSI load is reduced to account for wheel-turning load that cannot be curtailed. The wheel-turning load is forecast to be 6 aMW for each aluminum DSI. The reserves provided are 10 percent of the remaining forecast total DSI load, or 402 – 12 = 390; 390 × 0.10 = 39 MW of reserve capacity.

This quantity is converted to total kilowatts for a year by multiplying first by 1,000 kW per MW and then again by 12 months per year, resulting in an annual total of usable reserves of 468,000 kW. The total value of these DSI reserves is then computed by multiplying the kilowatts of capacity times the $6.02 per kW per month rate, resulting in a total annual value of DSI reserves of $2,817.360. The value of reserves adjustment to the IP rate is computed as this total annual value divided by the forecast annual DSI energy load of 402 aMW (which is 3,521,520 MWh), resulting in a value of $0.80 per MWh. See the following Summary.

Summary of DSI Value of Reserves:

Embedded Cost	$6.02	kW per month
Assumed DSI sale	402	aMW
Assumed Wheel-turning Load	12	aMW
Interruptible Load	390	aMW
Percent of DSI sale that is interruptible	10	percent
MW of interruptible load	39	MW
kW of interruptible load	39,000	kW
annual total kW of interruptible load	468,000	kW
Total value of Operating Reserves per year	$2,817,360	per year
Value converted to $/MWh on total load	$0.80	$/MWh

2.2.2 Monthly and Diurnal Differentiation of IP Energy Rates

Monthly and diurnal differentiation of IP energy rates is done based on the rate period average marginal cost of power as determined in the Market Price Forecast Study, WP-10-FS-BPA-03. The marginal costs are shown in Table 2.2.

Table 2.2
Marginal Cost of Power, $/MWh

	A	B	C	D	E	F	G	H	I	J	K	L
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH	$40.32	$42.10	$44.52	$48.58	$47.65	$45.40	$40.71	$40.03	$39.39	$42.11	$47.13	$46.09
LLH	$34.12	$37.37	$39.33	$40.73	$40.08	$37.99	$34.05	$28.16	$29.42	$36.21	$39.66	$40.76

The FY 2010-2011 IP energy rates are determined by adjusting the rates in Table 2.2 down by an equal percentage such that the IP energy rates will recover the amount of the total revenue requirement for the rate period allocated and classified to the IP energy rates. Documentation, WP-10-FS-BPA-05A, Table 2.10.

2.3 Monthly and Diurnal Differentiation of NR Energy Rates

Monthly and diurnal differentiation of NR energy rates is based on the rate period average marginal cost of power as determined by the Market Price Forecast Study, WP-10-FS-BPA-03. Those marginal costs are listed in Table 2.2.

The FY 2010-2011 NR energy rates are determined by adjusting the rates in Table 2.2 down by an equal percentage such that the NR energy rates will recover the amount of the total revenue requirement for the rate period allocated and classified to the NR energy rates. Documentation, WP-10-FS-BPA-05A, Table 2.11.

2.4 Demand, Factoring Service, and Load Variance

This section discusses rate design and its relationship to BPA's Core Subscription Products.

2.4.1 Core Subscription Products Principles

BPA's Core Subscription Products were developed based on the principle that Core Products are billed from a "common table of rates" to ensure equitable comparability of payment among purchasers of different types of Core Products. The common table of rates includes demand rates, heavy load hour (HLH) and light load hour (LLH) energy rates, and a load variance rate. The common table of rates is associated with a table of billing factors that shows the billing determinants appropriate to the specific products. *See* BPA Power Products Catalog, Appendix B, Core Product Billing Factors.

2.4.2 Demand Rates for Core Subscription Products

The purpose of the demand rate in the Core Subscription Products is to compensate BPA for three components of firm service: (1) the cost of firming bulk energy, including firm energy provided in flat amounts, as under the Block product; (2) the cost of "factoring" service, in which energy is distributed among hours to match a load shape; and (3) the cost of readiness to meet actual load under peak conditions. When combined with energy charges, a demand charge has the effect of increasing the purchaser's average payment per unit of product purchased, referred to as the average rate paid. If the power delivery is not flat (i.e., it is higher during the HLH period than the LLH period), the resulting demand charge plus energy charge makes the average rate paid higher than the average rate paid for a flat power purchase. To help maintain and ensure comparability, the same demand rate (in $/kW) will be applied to appropriate demand billing factors for PF Full Service, Partial Service, and Block products, and for any sales made at the IP and NR rates.

2.4.2.1 Development of Demand Rate

The rate design for PF, IP, and NR rates includes two energy rates for each month, one for HLH and one for LLH. However, the Market Price Forecast Study, WP-10-FS-BPA-03, demonstrates there is a different market value for power in each hour. To account for hour-to-hour differentials within each diurnal period, a demand rate ($/kW) is applied in conjunction with the HLH and LLH energy rates (mills/kWh, or $/MWh).

Monthly differentiation of the WP-10 demand rates is the same as that used for the current FY 2009 rates, based on the WP-07 Supplemental Final Proposal. The rates are listed in Table 2.3 below.

Table 2.3
PF Preference, IP, and NR Demand Rates

WP-07R for FY 2009, $/kW

	A	B	C	D	E	F	G	H	I	J	K	L
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
Demand	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82

WP-10 for FY 2010-2011, $/kW

	A	B	C	D	E	F	G	H	I	J	K	L
Demand	$2.05	$2.19	$2.30	$1.96	$1.99	$1.85	$1.74	$1.44	$1.32	$1.61	$1.89	$1.96

For the WP-10 PF Preference rates, the demand rates in Table 2.3 are adjusted up by the same percentage described in section 2.1. Documentation, WP-10-FS-BPA-05A, Table 2.7. The PF Preference Demand rates are also used for the IP and NR demand rates.

2.4.3 Factoring Service in Core Subscription Products

The term "factoring" is a term of general use in the utility industry. However, for purposes of the Core Subscription Products, the term is specifically defined to mean the BPA service of shaping a given quantity of megawatthours among HLH and LLH periods in each month to follow load. In this context, Factoring Service is an "energy-neutral" service. For example, a customer that has a 67 percent load factor (average monthly energy divided by monthly peak) generally would use more Factoring Service than a customer with a 75 percent load factor. A flat, or 100 percent load factor, purchase uses no Factoring Service. As a customer's load factor decreases (for example, to 57 percent from 67 percent), the load shape BPA must serve becomes more amplified, generally requiring more factoring of energy to meet the changes in the load.

The Factoring Service is a part of both the Full Service and Actual Partial Service products, as explained below. The amount of Factoring Service taken will be checked in the billing process only for those customers with declared dispatchable resources with hourly variability, and customers that purchase the Actual Partial (Complex) product or the Block with Factoring product. Customers without resources, customers whose resources are not dispatchable, and customers whose resources have fixed hourly quantities take and receive exactly the amount of Factoring Service to which they are entitled. Only when customer resources are dispatchable on an hour-to-hour basis is there a possibility of receiving Factoring Service amounts that are less than or greater than the entitlement amount. The BPA Power Product Catalog product descriptions provide further details on the factoring benchmark calculation. Factoring Service that is within the benchmark will result in no excess Factoring Service penalty charges. The entitled amount of Factoring Service will be paid at the PF Preference demand rate applied to the customer's power billing demand.

The Factoring Service is not intended to provide backup or other services for customer resource amounts that are interrupted or otherwise fail to be delivered. If a flat resource fails to be delivered for an hour to a customer within the BPA Balancing Authority Area (BAA), the power product default treatment is to identify that as an unauthorized increase event. By arrangement, other BPA services could apply, such as ancillary services acquired by the customer from Transmission Services or a negotiated backup service.

2.4.3.1 Factoring Service as a Staple-On Product and the Appropriate Billing Demand

The BPA Power Product Catalog states that a customer can purchase the Block Product with Factoring Service as a staple-on product. When Factoring Service is added to the Block Product, it provides within-day and within-month factoring of Block energy. This additional service is priced at the demand rate and applied to the appropriate demand billing factor.

2.4.4 The Demand Adjuster

The Demand Adjuster is a billing factor that preserves equitable comparability among customers purchasing different types of Core Products. Full Service Product customers are billed based on their load on BPA during the hour of BPA's monthly Generation System Peak (GSP). However, the demand billing factors for the Simple and Complex Actual Partial Service Products and the Block Product with Factoring are based on the customer's system peak load. Basing the demand billing factor on the customer's system peak load provides individualized price signals to the customer and allows the customer to adjust demand as necessary to respond to the price signal. However, using the same demand rate on customer-specific billing demand measures is not directly compatible with the concept of a common table of rates and would create a lack of comparability.

The Demand Adjuster is designed to resolve this lack of comparability by adjusting billing demand to achieve parity with a customer whose billing demand is measured on the GSP. Because a customer's system peak load is always equal to or larger than its load on the hour of the GSP, this larger billing factor for these alternative products, if not adjusted, would result in a higher relative demand billing than the Full Service Product. To maintain a level of comparability, given the different demand billing measurements for the products, the Demand Adjuster is used to scale down the Billing Demand of the Actual Partial Service Products and the Block Product with Factoring. The Demand Adjuster is a multiplier consisting of a number less than or equal to one. It is calculated by dividing the customer's Total Retail Load (TRL) on the hour of the GSP by the customer's TRL on the hour of the customer's system peak. The minimum Demand Adjuster is 0.6.

2.4.5 Load Variance Rate

Another Core Subscription Product, Load Variance, is defined as the variability from forecast of monthly energy consumption within the customer's system. Variability in monthly energy consumption may be caused by circumstances such as weather, economic business cycles, load growth, or load loss. Load Variance does not include the variance in load caused by annexation of new load, retail access, or service to new large single loads (NLSL). Such loads will receive Load Variance coverage once the loads are served by BPA under the applicable rate schedule. BPA offers to stand ready to serve the variability of a customer's load under the Full Service and Actual Partial Service products, and the Load Variance charge allows a customer's billing factors to follow actual consumption. The Load Variance charge is not applicable for purchase of Block products, where the amounts purchased are fixed in advance.

In establishing the Load Variance rate for FY 2010-2011, the PF-07R Load Variance rate of 0.46 mills/kWh is scaled up by the same percentage described in section 2.1. The PF Preference Load Variance rate is also used for the IP and NR demand rates, when applicable by contract.

2.5 Unauthorized Increase Charges and Excess Factoring Charges

Separate penalty rates are applied for Unauthorized Increases in Energy usage, Unauthorized Increases in Demand usage, Excess Within-Day Factoring Energy, and Excess Within-Month Factoring Energy. These rates apply to deliveries that exceed contractual entitlements. Minimum penalty rates for Energy, Demand, and Excess Factoring are included, with the potential for relevant price indicies to set effective rates for the month at higher levels than the identified minimums. Collectively, market prices reflected by the Dow Jones Mid-Columbia Index (DJ Mid-C Index) and the specified California Independent System Operator (CAISO) price index provide a basis for the potential opportunity cost (or actual purchase cost) to BPA of serving energy, demand, or factoring in excess of a customer's contractual entitlement. The inclusion of these market price indices in the penalty rate derivations also ensures an appropriate deterrent against customers placing demand, energy, and factoring burdens on the BPA system during periods of high market prices. Where the index-driven prices exceed the specified minimum rates for a given month, they will constitute the effective rates.

There is the possibility that one or more of the currently identified indices for determining the penalty charges will cease to exist during the rate period. The General Rate Schedule Provisions (GRSPs) account for this possibility by allowing a replacement index, either some index already in existence (e.g., the CAISO) or some other relevant future index available at some point during the rate period. GRSPs, sections II.H and II.Q.

A reduction in charges is available for single occurrences that trigger multiple penalties. Specifically, reductions to Excess Within-Month Factoring Charges are possible to the extent that energy in the same diurnal period is assessed the Unauthorized Increase in Energy Charge.

2.5.1 Unauthorized Increases in Energy and Demand

If specified in the applicable rate schedule, the charge for Unauthorized Increase in Energy will be applied for any purchaser taking energy in excess of its contractual entitlement. The rate for a given month will be the highest DJ Mid-C Index price for firm power or the highest hourly CAISO Imbalance Energy price for that month, whichever is greater. The minimum rate is 100 mills/kWh.

The rate for Unauthorized Increase in Demand will be applied to any purchaser taking demand in excess of its contractual entitlement. The minimum rate is three times the monthly Demand Rate from the applicable power rate schedule. The effective rate may be set at a level that exceeds this minimum based on the sum of the hourly CAISO Spinning Reserve Capacity prices during HLH for the month. The sum of hourly Spinning Reserve Capacity prices during all HLH of the month will be compared to the minimum and, if higher than the minimum, will determine the effective Unauthorized Increase in Demand rate.

2.5.2 Excess Factoring Charges

There are two separate charges for Excess Factoring: (1) the Excess Within-Day Factoring Charge and (2) the Excess Within-Month Factoring Charge. The Within-Day factoring test compares the hour-by-hour shape of the customer's load with the customer's hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kilowatthours, than the underlying load would have used. There are separate, but identical, tests for HLH Within-Day Factoring and LLH Within-Day Factoring. For both of these tests, the minimum Excess Factoring Charge rate for each month is 5 mills/kWh, although it is likely that the effective rates will be higher, as they are also defined by hourly CAISO Imbalance Energy prices. For HLH, the highest within-day difference during the month between the highest HLH price less the lowest (same day) HLH price, and the 5 mills/kWh minimum, will determine the effective rate. A corresponding test against the 5 mills/kWh minimum will be applied for the LLH difference to determine the LLH Excess Within-Day Factoring Charge rate.

The sum of the HLH Excess Within-Day Factoring amounts will be billed at the HLH Excess Within-Day Factoring Charge rate. The sum of the LLH Excess Within-Day Factoring amounts will be billed at the LLH Excess Within-Day Factoring Charge rate.

The Within-Month Factoring Test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-by-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The within-day factoring test (discussed above) is not equipped to identify a factoring service issue if, for example, a customer's resource deliveries were zero for a particular day. The within-month factoring test is equipped to address such an event, however. The within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess Within-Month Factoring for each diurnal period is the greater of: (1) the sum of the megawatthour amounts greater than the upper boundary; or (2) the sum of the megawatthour amounts less than the lower boundary. There will be a separate quantification of Excess Within-Month Factoring for HLH and for LLH. The minimum rate for Excess Within-Month Factoring is 5 mills/kWh. This minimum will be compared with rates derived from the DJ Mid-C Index prices for firm power and the CAISO Imbalance Energy indexes for the month. For HLH Excess Within-Month Factoring Energy, the effective rate will be the greatest of: (1) 5 mills/kWh; (2) the difference between the highest DJ Mid-C Index price for firm power among all HLH periods for the month and the lowest HLH DJ Mid-C Index price for firm power; and (3) the difference between the highest average hourly CAISO Imbalance Energy price among all HLH periods for the month and the lowest average hourly CAISO Imbalance Energy HLH price. An equivalent test against the 5 mills/kWh minimum rate will be done to determine the effective LLH rate for the Excess Within-Month Factoring Charge.

The Excess Within-Month Factoring energy quantities are reduced by any Unauthorized Increase Energy amounts in the same diurnal period, and only the residual is charged for Excess Within-Month Factoring.

2.6 Firm Power Products and Services (FPS-10) Rate

The FPS-10 rate is a market-based or negotiated rate, and it may have a demand component, an energy component, or both. Unbundled products also are available under the FPS-10 rate schedule at flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply to the extent required to purchases of firm power under the FPS-10 rate. The West-Wide Price Cap as established or approved by Federal Energy Regulatory Commission (the Commission) will apply to all sales under this rate schedule.

The FPS rate includes a fixed 7(b)(3) Supplemental Rate Charge to recover the section 7(b)(2) rate protection allocated to FPS rates pursuant to section 7(b)(3) of the Northwest Power Act. To retain maximum pricing flexibility, the flexible portion of the FPS rate may be negative, if necessary, so that the total FPS rate will be as negotiated between BPA and the purchaser.

2.7 Flexible PF and NR Rate Options

The Flexible PF and NR Rate Options are offered at BPA's discretion to PF Preference and NR purchasers who make contractual commitments to purchase under one of these options. The charges and billing factors under this option are specified by BPA at the time the Administrator offers to make power available to purchasers under this option. The actual charges and billing factors will be mutually agreed by BPA and the purchasers, subject to satisfying the following condition: forecast revenues from a purchaser under the Flexible PF or NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the appropriate rate schedule been applied to the same sales.

Notwithstanding the effective dates of the PF-10 and NR-10 rates and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF or NR Rate Option by purchasing under the Flexible PF or NR Rate Option will survive and be fully enforceable until such time as they are fully satisfied. GRSPs, sections II.I and II.J.

2.8 PF Exchange Rate

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). Under an RPSA, 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 in both parts is equal to the utility's eligible residential and small farm load. The difference between the amount BPA pays for purchases and the amount the BPA receives for sales determines monetary REP benefits paid to the utility by BPA. The PF Exchange rate also applies to BPA's actual power sales to exchanging utilities under contractual "in-lieu" provisions.

The PF Exchange rate is comprised two components: a common Base PF Exchange rate, and utility-specific 7(b)(3) Supplemental Rate Charges. Neither component of the PF Exchange rate is diurnally differentiated or contains an additional charge for demand.

2.8.1 7(b)(3) Supplemental Rate Charge

If the section 7(b)(2) rate test triggers, the Base PF Exchange rate will be adjusted by a utility-specific 7(b)(3) Supplemental Rate Charge. The Base PF Exchange rate, so adjusted, will be the PF Exchange Rate and will apply to each participant's exchange load in the calculation of its REP benefits. It may be that one or more utilities will apply for the REP after rates have been determined for the rate period. To minimize the risk to BPA and other customers of paying REP benefits that were not contemplated in setting rates, and to give some assurance that PF Preference purchasers are receiving section 7(b)(2) rate protection from increased exchange costs, the 7(b)(3) Supplemental Rate Charge applicable to a new REP participant will be the difference between its ASC and the Base PF Exchange rate.

2.8.2 Components of the Base PF Exchange Rate

The Base PF Exchange rate begins with the 7(b) rate pool rate, also known as the unbifurcated PF rate, determined prior to the section 7(b)(2) rate test. This is the precursor to the PF rate and, in the absence of a reallocation of costs resulting from the section 7(b)(2) rate test, would be the PF Preference rate. Any reallocation of costs due to the section 7(b)(2) rate test and the 7(b)(2) Industrial Adjustment 7(c)(2) Delta is added to the PF Exchange rate through a 7(b)(3) Supplemental Rate Charge.

The Base PF Exchange rate also contains a transmission cost component. The specific transmission services included in the Base PF Exchange rate are NT base transmission charges, transmission Load Shaping Charges, transmission Scheduling Service and Dispatch, Load

Regulation, and Operating Reserves. These transmission services are assumed to be acquired under transmission rate schedules for a load that has a 73 percent load factor. The total transmission cost included in the Base PF Exchange rate is \$4.26/MWh. The calculation of the \$4.26/MWh is shown below.

$$\$4.26/\text{MWh} = (((\text{NT Base Charge} + \text{Load Shaping Charge} + \text{Scheduling Service and Dispatch}) \times 12) \div (8760 \times 0.73)) + \text{Load Regulation} + \text{Operating Reserves}$$

Where

NT Base Charge	\$1,298	per MW per mo
Load Shaping Charge	\$367	per MW per mo
Schedule Service and Dispatch	\$203	per MW per mo
Monthly Total	\$1,868	per MW per mo
Annual Total	\$22,416	per MW per year
Load Factor Assumption	73	percent
Fixed Cost in \$/MWh	\$3.50	per MWh
Load Regulation	\$0.33	per MWh
Operating Reserves	\$0.43	per MWh
Total Costs for Transmission	\$4.26	per MWh

Transmission costs are included in the Base PF Exchange rate to make the rate comparable to a utility's ASC, which includes the utility's allowable transmission expense.

2.8.3 PF Exchange Rate 7(b)(3) Supplemental Rate Charges

Costs allocated to the PF Exchange rate after establishing the base PF Exchange rate are recovered through a 7(b)(3) Supplemental Rate Charge. A distinct 7(b)(3) Supplemental Rate Charge is calculated for each REP participant. The 7(b)(3) Supplemental Rate Charge recovers each participant's allocated share of the cost of section 7(b)(2) rate protection plus the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. 7(b)(3) Supplemental Rate Charges are subject to change during a rate period each time a participant's ASC changes during that rate period or if a participant gains or loses service territory due to annexation.

2.8.4 PF Exchange Rate 7(b)(3) Supplemental Rate Charges

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2.9 Irrigation Rate Mitigation Product

The Irrigation Rate Mitigation Product (IRMP) is a contract-specific rate and not part of the rate design. The estimated difference between the forecast revenue at PF rates and IRMP rates, $12.036 million per year, is accounted for as an expense in setting rates. Documentation, WP-10-FS-BPA-05A, Table 2.5.5.

2.10 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 purchasers with low system densities, BPA shall apply, to the extent appropriate, discounts to the rate or rates for such purchasers. Such purchasers are utilities with low system densities and with high distribution costs resulting from sparsely populated service areas. The Low Density Discount principles, eligibility criteria, and discount appear in the GRSPs, Section II.L.

The LDD is determined by two formulas. One formula calculates a qualifying utility's ratio of Total Retail Load to its depreciated electric plant, excluding generation plant (the Kilowatt-hour/Investment or K/I ratio). The other formula calculates the ratio of the number of the utility's consumers to the number of pole miles of distribution lines (the Consumers/Mile or C/M ratio). These ratios are computed with data submitted by the purchaser based on the purchaser's entire electric utility system in the Pacific Northwest (PNW). For purchasers with service territories that include any area outside the PNW, BPA compiles data submitted by the purchaser separately on the portion of the purchaser's system that is in the PNW. BPA applies the eligibility criteria and discount percentages to the purchaser's system within the PNW, and where applicable, also to its entire system inside and outside the PNW. The purchaser's eligibility for the LDD is determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, at its sole discretion, may waive the requirement to submit separate data for a purchaser with a small amount of its system outside the PNW.

The discounts under each ratio range from zero to 5 percent, in increments of one-half percent. The discounts from the two ratios are added together to determine the total discount to purchases under an applicable rate. The LDD for any utility is capped at seven percent.

A change in the discount for any eligible utility will be ramped in from the pre-existing discount. No eligible utility will experience more than a one-half percentage point change (positive or negative) in its LDD beginning October 1, 2006, and each succeeding fiscal year, until the revised LDD percentage is attained. If a utility fails to satisfy the initial eligibility criteria, however, the discount will be zero and will not be ramped in from the existing discount.

The estimated cost of the LDD is $26.4 million for FY 2010 and $26.5 million for FY 2011. See the Documentation, WP-10-FS-BPA-05A, Table 4.10, for an example of the calculation for an individual customer.

2.11 Conservation and Renewables Program

BPA provides financial assistance to BPA's customers to develop conservation savings and renewable resources. The Conservation Rate Credit (CRC) is intended to help implement the program goals set forth in BPA's policy for the development of regional conservation and renewable resources. BPA is looking to its customers to be in the vanguard of conservation and renewable resource development in the region. Program goals for both programs were developed as part of Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy) and accompanying Administrator's Record of Decision (Near-Term Policy ROD). The Near-Term Policy ROD is available at www.bpa.gov/power/pl/regionaldialogue/02-2005_rod.pdf. The structure and program design for the CRC were developed through a collaborative workgroup process. As part of the Regional Dialogue, BPA looked to the collaborative workgroup process to assist in developing a fully defined conservation proposal. The collaborative process started in September 2004 and resulted in the post-2006 conservation program structure. Documentation, WP-10-FS-BPA-05A, Appendix D; *see also* Appendices B and C.

BPA's Near-Term Policy expresses five principles to guide the development of conservation acquisition programs for post-2006. In brief, these principles are: (1) use the Northwest Power and Conservation Council's plan to identify the regional cost-effective conservation savings targets upon which BPA's share (approximately 40 percent) of cost-effective conservation is based; (2) achieve the bulk of the conservation savings at the local level; (3) meet BPA's conservation savings goals at the lowest possible cost to BPA; (4) provide an appropriate level of funding for local administrative support to plan and implement conservation programs; and (5) provide an appropriate level of funding for education, outreach, and low-income weatherization such that these important initiatives complement a complete and effective conservation portfolio.

2.11.1 Conservation Rate Credit

To encourage its customers to undertake conservation savings projects and develop renewable resources, BPA makes the CRC available to customers who purchase power under the PF-10 (including the Slice rate but not the PF Exchange rate), IP-10 (except aluminum smelters), and NR-10 rate schedules. Documentation, WP-10-FS-BPA-05A, Appendix C.

The discount for the CRC is 0.5 mills/kWh. The 0.5 mills/kWh rate discount was originally established as the WP-02 Conservation and Renewables Discount (C&RD) rate discount. These rates continue the CRC for FY 2010-2011 rate period at the same rate credit. To estimate the total cost of the CRC, 0.5 mills/kWh is multiplied by the forecast loads purchasing power under the eligible rate schedules. Customers eligible to receive the CRC would not be required to reduce the amount of firm requirements power they purchase from BPA. CRC costs are included in the Cost of Service Analysis (COSA) (see WPRDS section 3) as part of conservation program costs.

Customers' monthly BPA power bills reflect the CRC as a line item. Individual monthly credits on bills are 0.5 mills/kWh multiplied by one-twelfth of the customer's forecast annual purchases from BPA under its Subscription contract. For Slice customers, the forecast annual purchase is based on each customer's contractual percentage share of 7,070 aMW. For non-Slice customers, the forecast annual purchases are based on the forecast of each customer's net requirements as established in the Loads and Resources Study Documentation, WP-10-FS-BPA-01A, Sections 2.2.1 and 2.2.2. Each customer's expected series of 24 equal monthly line item credits to its power bill is calculated prior to the FY 2010-2011 rate period. Based on compliance with BPA's Conservation and Renewables Implementation Guidelines, BPA reserves the right to adjust the specific amount of CRC received by each customer as necessary throughout the rate period. GRSPs, Section II.A.

These rates assume the CRC will generate no net revenue during the rate period and that all eligible customers will participate in the CRC. Participation in the CRC program occurs when customers accept the credit on their monthly bills. As participants, customers accept responsibility to make appropriate expenditures in conservation and renewable resources during the rate period as set forth in BPA's Conservation and Renewables Implementation Guidelines, as amended by establishment of the CRC. Each customer participating in the CRC program will administer its CRC activities pursuant to the most-current CRC Implementation Manual or its successor. Customers may opt out of the CRC program by notifying BPA. BPA will remove the CRC from non-participating customers' monthly bills. Consistent with the terms of the customer's Subscription power sales contract with BPA, failure to make the appropriate expenditures will result in the customer reimbursing BPA the difference between the amount of the CRC received and the customer's actual total qualifying expenditures.

With help from the Northwest Power and Conservation Council Regional Technical Forum (RTF), criteria to determine qualifying expenditures were established to implement the C&RD and are continuing for the CRC. After several years of practice, BPA and its customers have experience with hundreds of qualifying expenditures, which may, at times, be reassessed to determine their cost and benefit. For example, BPA may ask the RTF to conduct periodic energy savings performance evaluations at the regional level with appropriate power customer involvement. These evaluations will assist in the determination of future adjustments to the savings credited for measures and program designs in the CRC. BPA expects that the list of cost-effective measures will be updated during the rate period to reflect revised cost-effectiveness standards and eliminate measures that are not cost-effective.

Customers participating in the CRC program must submit a final report on qualifying expenditures as required at the end of the customer's discount period. The discount period is the term of the customer's Subscription power sales contract. BPA will evaluate the customer's total qualifying expenditures for conservation and renewable option projects during the rate period. When documented total qualifying expenditures are less than the sum of the monthly billing credits for the rate period, customers will be required to reimburse BPA for the difference, pursuant to the late payment provision of the Subscription contract. *Id*.

BPA will account for the energy savings that are produced through the CRC and from BPA-funded participation in Northwest Energy Efficiency Alliance (NEEA) conservation activities for purposes of achieving BPA's share of the Northwest Power and Conservation Council's conservation savings target. Such savings will not be reflected as reductions in the customers' firm net requirement loads during the FY 2010-2011 rate period.

Slice and/or Block customers that sign bilateral contracts with BPA obligating the customers to deliver actual energy savings will be required to reduce their firm net requirements loads. Documentation, WP-10-FS-BPA-05A, Appendix C.

BPA reserves the right to review the implementation of conservation programs funded through the CRC program. BPA may inspect and/or audit customers to verify claims of units or completed units of conservation savings and monitor or review utility records and verified energy savings method and results. The number, timing, and extent of such audits shall be at the discretion of BPA. *Id.*

2.11.2 Renewable Option of the Conservation Rate Credit

A Renewable Option is included as part of the CRC program. A utility customer participating in the Renewable Option is required to request annual funding for eligible renewable resource activities (as prescribed in the CRC Implementation Manual) at least three months prior to the beginning of each fiscal year of the rate period. When renewable energy option participation requests in the CRC exceed the capped dollar amounts, participants will be subject to *pro rata* reductions. Customers must submit progress reports pursuant to the CRC Implementation Manual or its successor.

2.12 Green Energy Premium (GEP)

The GEP is a charge added under applicable rate schedules when a customer chooses to designate any portion (up to 100 percent) of its Subscription purchase as Environmentally Preferred Power (EPP), or its successor, or Alternative Renewable Energy (ARE). GRPSs, Section II.K. By paying the GEP, BPA's customers receive the non-power renewable attributes (e.g., Renewable Energy Certificates (RECs)) associated with EPP and ARE. The amount of EPP and ARE that customers may purchase will be limited by availability and the amount of an individual customer's Subscription firm power purchase. To derive the price of EPP and ARE, BPA will consider the forecast value of environmental attributes expected to be produced by resources included in the portfolio and any contractual call rights for EPP and ARE.

During the FY 2010-2011 rate period, customers and BPA may agree to amend the Subscription contracts to convert the sale of EPP to the sale of RECs. In such event, the language herein that applies to EPP shall apply to RECs.

2.13 Targeted Adjustment Charge

Under the PF-10 (with the exception of the PF Exchange rate and the Slice rate) and NR-10 rate schedules, all customer firm power requests for unexpected additional load service that occur after June 30, 2008, will be subject to a Targeted Adjustment Charge (TAC). GRSPs, Section II.P. Once established, the TAC will apply to that customer for the duration of the rate period. The TAC will be applied to customers that annex load, new public customers requesting requirements service, and retail access load gain or returning load. The TAC will not applied to amounts of power purchased under a customer's initial Subscription contract. For the subsequent rate period (FY 2012-2013), where such load can be incorporated into the load forecast in the WP-12 rate proceeding, the customer would qualify for PF rate service without the TAC.

The TAC will apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load that was previously served by that customer's own resources as provided under sections 5(b)(1)(A) and (B) of the Northwest Power Act.

BPA may exempt new load from the TAC and apply the PF-10 rate if a public agency customer is annexing or otherwise taking on the obligation of load from another public agency customer in such a manner that BPA's total load obligation does not increase. In this situation, however, the TAC would apply if the annexed requirements load has been previously served by the customer's 5(b)(1)(A) or 5(b)(1)(B) resources, because this would increase BPA's total load obligation.

BPA may exempt any load from the TAC and offer the otherwise applicable rate if the new load is forecast to be less than 1 aMW per year. In this situation, the Administrator may waive the TAC if it is determined to be inconsequential to overall costs.

In a situation where a public agency customer annexes load previously served by an IOU, and such IOU is receiving REP benefits, the IOU will realize a reduction in the amount of its REP benefit payment. BPA will account for such reduced REP benefits as an offset against the TAC charged to the public agency customer. The public agency customer will be responsible for any TAC in excess of the amount of the offset.

The TAC will apply for the duration of the customer's contract or through FY 2011, whichever occurs first. If a new public agency customer requests service, the TAC would apply through FY 2011.

No loads are forecast to be served under a TAC. However, the provision for a TAC is included to recover the cost of power purchases, if any, that BPA must undertake to serve unexpected incremental load. The TAC is intended to recover the incremental costs incurred and is not otherwise included in Power Services revenue requirement for FY 2010-2011. If the cost of power to serve these loads is above BPA's embedded costs, BPA's financial reserves would be affected. The TAC will minimize the erosion of BPA financial reserves that could occur from additional costs to meet unanticipated increases in load.

The TAC would be calculated in response to an individual customer's request and would be determined based on the amount of power available to serve incremental requests from monthly Federal system surplus using critical water conditions, excluding balancing purchases and purchases for System Augmentation included in the resources used to set power rates for the period. This determination will use the monthly available Federal firm system energy that can be used to serve this load. To the extent there is available Federal firm system energy in any month(s), it would be used to serve the TAC load for that month and reduce the total cost of the TAC service.

If sufficient Federal firm system power is available to serve the incremental load, such power shall be sold at the PF-10 rate or the NR-10 rate. In the event sufficient Federal firm system power is not available and BPA must acquire additional power to meet the incremental load, such additional power shall be sold at the PF-10 rate or the NR-10 rate, plus a TAC reflecting the difference between the PF-10 rate or NR-10 rate and BPA's cost to supply this power.

BPA will calculate the total cost of the additional power for a specific customer request based on BPA's estimated monthly cost to purchase resources plus an administrative fee, including any additional incurred costs to serve the incremental load. These additional costs may include, where applicable, transmission, ancillary services, losses, and/or other charges incurred in purchasing power from other entities. The Net Present Value (NPV) of the expected PF or NR revenues will be subtracted from the NPV of the total cost, and the remainder will be levelized across the total megawatthours of the incremental load to obtain a levelized mills/kWh charge that will be the TAC rate. That TAC rate will be applied to all energy delivered to the incremental load, even in months where there was sufficient FBS to serve the load.

The TAC rate will not reduce the total price for power below the PF-10 rate or the NR-10 rate, whichever is applicable. The TAC will be applied in addition to the monthly HLH and LLH energy rates, demand rate, and load variance rate for the applicable month or months as specified in the applicable rate schedules.

BPA will calculate the cost basis for a TAC at the time a customer requests power under this schedule. The TAC will be finalized prior to signing a final contract or before initial deliveries of energy, whichever is first.

In order to encourage renewable resource development in the region, BPA will allow a limited exception to the application of the TAC to customers that buy or develop renewable resources. If a customer is serving a portion of its load with either a certifiable renewable resource eligible for the CRC or a contract purchase of certified renewable resource power eligible for the CRC for a period shorter than the FY 2010-2011 rate period, such customer may request additional requirements firm power service during the rate period for such load at the PF-10 rate without being subject to the TAC.

2.14 Transfer Services

Two separate charges may apply to power customers BPA serves by transfer. These charges, the GTA Delivery Charge and the Transfer Service Operating Reserve Charge, address distinct aspects of Transfer service. This section also addresses the Supplemental Direct Assignment Guidelines applicable to customers purchasing power from BPA by way of transfer service.

2.14.1 GTA Delivery Charge

The GTA Delivery Charge 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 otherwise been directly assigned to the specific customer.

Since 2002, the GTA Delivery Charge has mirrored Transmission Services Utility Delivery Charge. For the FY 2010-2011 rate period, the components of the GTA Delivery Charge are proposed to continue to mirror the Transmission Services Utility Delivery rate and billing factor under the posted Delivery Charge schedule in the approved transmission and ancillary services rate schedules. The GTA Delivery Charge would change following a change to the Utility Delivery Charge.

The GTA Delivery Charge revenue forecast is approximately $2.7 million per year, as shown in Table 2.4 below. This revenue forecast was derived by applying the proposed GTA Delivery Charge of $1.119 per kilowatt per month to the forecast peak loads of the customers that pay the GTA Delivery Charge.

Table 2.4
Forecast Revenue from GTA Delivery Charge

	FY2010	FY2011
October	$ 181,940	$ 186,853
November	$ 230,073	$ 235,936
December	$ 232,763	$ 238,415
January	$ 260,231	$ 266,311
February	$ 212,487	$ 217,664
March	$ 204,597	$ 209,633
April	$ 222,315	$ 227,807
May	$ 187,042	$ 191,312
June	$ 203,273	$ 208,057
July	$ 211,954	$ 216,736
August	$ 217,528	$ 222,522
September	$ 341,706	$ 350,026
Total	$ 2,705,907	$ 2,771,271

2.14.2 Supplemental Direct Assignment Guidelines

In accordance with the July 2007 Regional Dialogue Policy and Record of Decision, BPA includes in the GRSPs the Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements (Supplemental Direct Assignment Guidelines). GRSPs, Section I.E. 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 to assign specific facility or expansion costs to particular Transfer service customers.

2.14.3 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is a new charge that 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 would have already paid the required Operating Reserve transmission charge. As described in more detail in section 5.4 of the Generation Inputs Study, WP-10-FS-BPA-08, the Commission is considering a WECC proposal to change this requirement. The proposed WECC change would reduce the Operating Reserve obligation of the BPA BAA for transfer service customers and shift a portion of the obligation to the BAAs in which transfer service customers reside. This change, if adopted, is expected to result in added BPA expense for Operating Reserve supplied by third-party transmission providers.

The Transfer Service Operating Reserve Charge will recover these additional rate period costs. GTA-10 rate schedule, Section II. In general, the Transfer Service Operating Reserve Charge mirrors Transmission Services ACS-10 charge for Operating Reserves. The charge will apply to power customers when the following three conditions are met: (1) BPA serves the power customer by transfer; (2) the power 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. For customers that meet the above criteria, the Transfer Service Operating

Reserve Charge will charge the same rate for Operating Reserves that Transmission Services charges customers that have load in the BPA BAA. The Transfer Service Operating Reserve Charge will begin if and when the proposed change to the Operating Reserve requirements, as described in section 5.4 of the Generation Inputs Study, WP-10-FS-BPA-08, is adopted by the Commission and implemented by Transmission Services.

BPA is assuming that the proposed WECC change in Operating Reserve will be implemented April 2010. However, the forecast revenue associated with the Transfer Service Operating Reserve Charge is zero since 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 paid to third-party transmission systems.

2.15 Slice of the System (Slice) Product, Slice Revenue Requirement, and Slice Rate

2.15.1 Slice Product Description

The Slice product is a power sale of a fixed percentage of the generation output of the FCRPS. It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The percentage is based upon a Slice customer's annual firm net requirement load, and power delivered under the Slice product is shaped to BPA's generation output from the FCRPS. BPA's Subscription sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

Because the power delivery under the Slice product is calculated as a percentage of the FCRPS generation output, the actual amount of power delivered to the Slice customer varies throughout the year. During certain periods of the year and under certain water conditions, the power delivered may exceed the Slice customer's firm net requirement and may, at times, exceed the

Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements power and surplus power.

2.15.2 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatthour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay a percentage of the Slice Revenue Requirement.

2.15.3 Inclusion and Treatment of Expenses and Revenue Credits

The Slice Revenue Requirement includes the same expenses and revenue credits as are included in the Power revenue requirement, with certain limited exclusions. In general, there are three types of excluded expenses: (1) power purchases, except those associated with the inventory solution (augmentation); (2) inter-business line transmission costs, except those associated with serving BPA system obligations and GTAs; and (3) Planned Net Revenues for Risk (PNRR) (or successor risk mitigation tools) and hedging expenses, except those hedging expenses associated with the inventory solution. See Table 2.5, Slice Product Costing and True-Up Table, for a detailed list of the line items and forecast dollar amounts in the Slice Revenue Requirement.

The following paragraphs clarify the rate treatment of particular items in the Slice Revenue Requirement and Actual Slice Revenue Requirement. The Slice Revenue Requirement includes all the forecast expenses and revenue credits that are the basis for calculating the Slice rate for FY 2010-2011. The Actual Slice Revenue Requirement will include the same expense and revenue credit categories as the Slice Revenue Requirement, but will be comprised of the final audited actual expenditures and revenues as reflected on BPA's Power Services financial statements. The Actual Slice Revenue Requirement for a given fiscal year is used as the basis for the calculation of the annual Slice True-Up Adjustment Charge for that fiscal year. See section 2.15.5 for a more detailed description of the Slice True-Up process.

2.15.3.1 Augmentation Expenses

The Slice Revenue Requirement includes expenses for power purchases to augment the capability of the Federal system to meet the total load placed on BPA. These augmentation power purchases are those needed to meet all load service requests made under BPA's Subscription contracts on a planning basis. For ratemaking purposes, augmentation purchases are considered to be separate and distinct from balancing purchases. See section 3.2.1.2.2 for a description of balancing power purchases. Slice customers do not pay for BPA's balancing purchases, as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

Slice customers are required to pay their proportionate share of the net cost of all augmentation expenses. The "net cost" of augmentation refers to the expenses associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power at the PF Preference rate. Slice customers do not receive any of the power associated with these augmentation purchases.

Augmentation expenses during the FY 2010-2011 rate period are forecast for FY 2010 to be $178.10 million, based on $42.74/MWh for 476 aMW of unspecified augmentation. Augmentation expenses also include $29.54/MWh for 10.3 aMW of Excess Requirements Energy (ERE) purchased from Slice customers, as described in section 4.5.1. For FY 2011, the forecast augmentation expenses are forecast to be $271.045 million, based on $45.48/MWh for 680 aMW of unspecified augmentation plus $29.81/MWh for 7.6 aMW of ERE purchased from Slice customers. These aMW amounts augment the capability of the Federal system to meet the total load placed on BPA, part of which includes service to 402 aMW of DSI load. See section 2.15.3.6. The augmentation aMW amounts have been divided into two parts, an amount to serve DSI load and an amount to serve non-DSI (PF) load. The augmentation amount for service to 402 aMW of DSI load includes an additional amount (2.82 percent of DSI load) to account for transmission losses. The remaining augmentation aMW amount is divided by a factor of 1.0282 to derive the the amount of non-DSI load that the augmentation power is assumed to serve. See Table 2.5, Slice Product Costing and True-Up Table, lines 142-152.

The revenues associated with the sale of non-DSI augmentation power are estimated based on the average PF Preference rate for power and multiplied by the amount of power that would be sold (70.7 aMW for FY 2010 and 267.1 aMW for FY 2011). The average PF Preference rate is assumed to be $28.77/MWh for FY 2010-2011. The DSI revenues are forecast based on the IP rate for power and multiplied by the amount of power that would be sold (402 aMW for FY 2010 and 402 aMW for FY 2011). The expected DSI and non-DSI revenues are subtracted from the forecast augmentation purchase expense to calculate the net cost of the augmentation purchases for FY 2010-2011. The net cost of augmentation power for FY 2010-2011 will not be subject to the Slice True-Up process.

2.15.3.2 Conservation Augmentation

Conservation Augmentation (ConAug) was the conservation component of BPA's inventory solution in the WP-02 Final Proposal. ConAug was a resource acquisition effort to purchase conservation measures to reduce BPA's load obligation.

The annual costs of ConAug were estimated and included in the augmentation expenses for the FY 2002-2006 Slice Revenue Requirement. Because it was not known specifically during the WP-02 rate proceeding how the ConAug program would be implemented, the annual costs were derived as if the load reduction was equivalent to a power purchase. The estimate of ConAug costs was based on the assumption that 20 aMW of ConAug would be purchased each year during FY 2002-2006. The cost of this power was estimated to be 28.1 mills/kWh plus 10 percent, or 30.9 mills/kWh, and was included as part of the Slice Revenue Requirement.

In the WP-02 Final Proposal, BPA set the ConAug expense as a fixed amount that was not subject to the Slice True-Up. This fixed amount was limited to the first 20 aMW of ConAug acquired each year during FY 2002-2006. Slice customers paid their share of the estimated costs of 100 aMW of ConAug during FY 2002-2006. If BPA acquired more than 20 aMW during any given year, those costs were allocated through the Load-Based Cost Recovery Adjustment Clause (LB CRAC) and included in related charges to both Slice and non-Slice customers.

BPA decided to capitalize the costs of actual ConAug acquisitions subsequent to the WP-02 Supplemental Final Proposal. As a result, there are annual amortization expenses associated with ConAug investments from FY 2002-2006 that carry over into FY 2010-2011. See Revenue Requirement Study Documentation, WP-10-FS-BPA-02A, Table 3G. These investments are amortized over the term of the Subscription contracts and are not fully amortized until 2011. However, Slice customers will not pay for these ConAug amortization costs in FY 2010-2011, because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization is excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement for FY 2010-2011.

2.15.3.3 IOU Residential Exchange Program (REP) Benefits

Slice customers are obligated to pay their proportionate share of the expenses associated with the IOU REP (as well as the cost of the REP for consumer-owned utilities – see section 2.15.3.4). The REP restarted beginning October 1, 2008. Consistent with the Slice Rate Methodology, the expenses associated with the IOU REP will be included in the Slice Revenue Requirement; see Table 2.5, line 28.

2.15.3.4 Cost of the Residential Exchange for COUs

Slice customers are responsible for paying their proportionate share of the expenses associated with the REP benefits for consumer-owned utilities (COUs). An amount of expenses associated with the REP for COUs is forecast for FY 2010-2011 and included in the Slice Revenue Requirement, as shown on Table 2.5, line 27.

2.15.3.5 Bad Debt Expense

The Slice Revenue Requirement contains a line item labeled "Bad Debt Expense," based on the line item in Power Services Statement of Revenues and Expenses. No amounts are forecast for bad debt expense for FY 2010-2011. However, the Actual Slice Revenue Requirement may contain an actual amount accounted for as bad debt expense. In the Actual Slice Revenue Requirement, for Slice True-Up purposes, any bad debt expense associated with the sale to any customer that purchases exclusively at the FPS-10 rate will be excluded from the Actual Slice Revenue Requirement. However, any bad debt expense associated with the sales to customers who purchase power at both the PF-10 and FPS-10 rates, along with any bad debt expense associated with the sales to customers who purchase power at the PF-10 rate only, will be included in the Actual Slice Revenue Requirement. These treatments are consistent with what was adopted in the Partial Resolution of Issues in the WP-07 rate case. WP-07-A-02, Attachment 1. Through the annual Slice True-Up, Slice customers will pay their proportionate share of the eligible bad debt expenses.

BPA reversed the True-Up Adjustment charges to Slice customers for the bad debt expense arising out of transactions with the CAISO and California Power Exchange (Cal PX) prior to

October 1, 2001. As a result, Slice customers will not receive any credit for recovery of any related outstanding receivables that BPA collects. Nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO or Cal PX receivables. This treatment is specified by the Slice Settlement Agreement (07PB-12273). The Slice Settlement Agreement is effective through September 30, 2011.

Allowances for uncollectible DSI liquidated damages for FY 2002 or prior years will not be included in the Actual Slice Revenue Requirement or Slice True-Up Adjustment Charge. Slice customers will not receive credit for recovery of receivables that BPA collects from DSIs. This treatment is specified by the Slice Settlement Agreement.

2.15.3.6 Costs of DSI Service

On June 30, 2005, BPA's Administrator signed the Record of Decision *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million, plus 17 aMW of power to Port Townsend Paper Corporation, for FY 2007-2011. These service benefits were provided to the aluminum smelters through monthly payments. The annual amounts of such service benefits were included in the Slice Revenue Requirement and subject to the annual Slice True-Up. Slice customers paid their proportionate share of the costs associated with these service benefits to the DSIs.

In December 2008, the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit) issued a decision in *Pacific Northwest Generating Cooperative et al. v. Department of Energy*, *slip op.*, Case No. 05-75638 at 16513 (9th Cir. 2008), that rejected aspects of the contractual arrangements for service benefits to the DSIs. For ratesetting purposes, it is assumed that BPA will provide service to 385 aMW of aluminum smelter load and 17 aMW of load at Port

Townsend Paper, for which it will acquire a total of 413 aMW of augmentation power to serve these loads. (The difference between 402 aMW of load and 413 aMW of augmentation power represents transmission losses.) The Slice Revenue Requirement includes the net cost of DSI augmentation of $32.9 million in FY 2010 and $42.8 million in FY 2011. The net cost of DSI augmentation is the difference between augmentation power expenses and DSI revenues for sales at the IP rate. Table 2.5, line 149. The augmentation for DSI service is being treated separately from the balance of the augmentation solely for the purposes of the development of the Slice Revenue Requirement. The treatment of this portion of the augmentation expenses should not be viewed to mean that the DSI load represents an incremental load for BPA. As noted in section 2.15.3.1, BPA augments to meet its total system load, which includes both PF and DSI loads. Slice customers will pay their proportionate share of the total net cost of augmentation, which will be included in the Slice Revenue Requirement. The total net cost of augmentation is not subject to the Slice True-Up.

2.15.3.7 Fish and Wildlife Program Costs

Slice customers are obligated to pay their proportionate share of BPA's costs for fish and wildlife, both BPA's direct program costs and U.S. Army Corps of Engineers and U.S. Bureau of Reclamation costs. Slice customers will also experience their proportionate share of BPA's indirect, or operational, program costs for fish and wildlife directly, through reduced or changed Slice power deliveries.

If BPA's fish and wildlife obligations differ from the forecasts contained in the Slice Revenue Requirement, Slice customers will pay their proportionate share of any increase or decrease in fish and wildlife annual expenses through their annual True-Up. Slice customers would be affected in real time for any changes in indirect program costs (e.g., changed operations or increases in spill and flow) for fish and wildlife through changes in their Slice power deliveries.

2.15.3.8 Slice Implementation Expenses

Slice Implementation Expenses are defined as those costs reasonably incurred by Power Services in any Contract Year (same as BPA's fiscal year) for the sole purpose of implementing the Slice product and that would not have been incurred had BPA not sold Slice Output under the Block and Slice Power Sales Agreement. Therefore, if BPA incurs costs during any Contract Year solely for the purpose of implementing the Slice product, these expenses would be charged 100 percent to the Slice customers through the annual Slice True-Up.

Consistent with BPA's Software Capitalization Policy and Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block/Slice Power Sales Agreement will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice contract term, which ends on September 30, 2011.

Slice Implementation Expenses in any given Contract Year will be accounted after the audited year-end Actual Slice Revenue Requirement is available for that Contract Year. Slice Implementation Expenses will be charged to Slice customers through the annual Slice True-Up for that Contract Year.

2.15.3.9 Debt Optimization Program

Through the Debt Optimization Program, BPA refinances (i.e., extends the maturities of) Energy Northwest bonds as they come due and repays an equivalent amount of Federal debt. In total, the same amount of debt is repaid as scheduled through the ratesetting process, but with an emphasis toward repaying Federal debt rather than non-Federal debt. See Revenue Requirement Study, WP-10-FS-BPA-02, section 2.3.

The financial effects from the refinancing and the related additional amortization of Federal debt are properly and fully accounted for in the Actual Slice Revenue Requirement, in accordance with the manner in which they are accounted for in Power Services' statement of revenues and expenses and in the determination of business line financial reserves.

The Debt Optimization Program is a BPA debt management policy that affects not only the Slice rate (through the annual True-Up Adjustment Charge), but BPA's rates of general application through the implementation of the CRAC. Inclusion of the Debt Optimization Program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

2.15.3.10 Reinvestment of "Green Tag Revenues" in BPA's Renewable Resources Facilitation and Research and Development

BPA will reinvest what it refers to collectively as "Green Tag revenues" in BPA's renewable resource facilitation and in renewables research and development. These Green Tag revenues come from three sources: (1) Green Energy Premium revenues resulting from sales of Environmentally Preferred Power; (2) Green Tag revenues resulting from sales of Renewable Energy Certificates; and (3) revenues from sales of Alternative Renewable Energy to pre-Subscription power purchasers. The renewables expense associated with the reinvestment of "Green Tag revenues" is excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement, consistent with the treatment adopted in the Partial Resolution of Issues in the WP-07 rate case, WP-07-A-02, Attachment 1. In addition, Slice customers will share in the revenues from the sale of Green Energy Premiums associated with the Klondike III resource. See Table 2.5, Slice Product Costing and True-Up Table, line 139.

2.15.3.11 Revenues from Generation Inputs for Integration of Wind Generation

Power Services will provide to Transmission Services the balancing requirements needed for wind generation (which includes regulation, load following, and generation imbalance). These requirements for wind generation are expected to significantly increase Power Services provision of generation inputs to Transmission Services as the projected amounts of wind generation come on line in the next few years.

The inter-business line revenues from Power Services provision of balancing reserves for wind generation are estimated to be $90.3 million in FY 2010 and $102.7 million in FY 2011. These estimates represent a significant increase over historical amounts of inter-business line revenues that Power Services has received for its provision of generation inputs for ancillary and other services. Slice customers will receive their proportionate share of the actual amount of such revenues through the Slice True-Up.

These generation inputs related to balancing reserves for wind generation are considered a system obligation for Slice operational purposes. The WP-02 rate case determined that Slice customers are responsible for bearing a proportionate share of Power Services costs associated with system obligations. WP-02-FS-BPA-05, Appendix C, section 4.5. The Slice customers therefore receive a credit based on a proportionate share of any revenues associated with the system obligations.

2.15.3.12 Minimum Required Net Revenue Calculation

Minimum Required Net Revenue (MRNR) is a component of the annual Generation Revenue Requirement. Revenue Requirement Study, WP-10-FS-BPA-02, section 4.1.2. MRNR also is a component of the Slice Revenue Requirement. The annual amounts for MRNR in the Slice Product Costing and True-Up Table are different from the amounts that appear in the total Generation Revenue Requirement. The differences are due to one element in the MRNR calculations. In the total Generation Revenue Requirement, accrual revenues that are included in the revenue forecast must be taken into account. Because these are non-cash revenues, the MRNR calculation must adjust cash from current operations to ensure adequate coverage of the annual cash requirements in order to demonstrate full cost recovery for proposed power rates. These accrual revenues stem from a settlement in which Power Services received cash payments that, in the accounting treatment, are recognized as revenues on a straight-line basis over the remainder of the term of the settled contracts. However, these settlements and the associated accrual revenues are not relevant to cost recovery for Slice and do not appear in the calculation of MRNR for the Slice Revenue Requirement. Due to this difference, the MRNR in the Slice Revenue Requirement is smaller than the MRNR in the total Generation Revenue Requirement.

2.15.4 Slice Rate

The Slice Revenue Requirement is the basis for calculating the base Slice rate. To calculate the proposed Slice rate for FY 2010-2011, the total dollar amounts for each fiscal year of the Slice Revenue Requirement are summed and divided by 24 months (the number of months in the rate period) and divided by 100 to obtain the base Slice rate per percent of Slice product purchased. See Table 2.5, Slice Product Costing and True-Up Table. The monthly Slice rate for FY 2010-2011 is $1,962,525 per one percent Slice product purchased.

2.15.5 Slice True-Up

Because the Slice rate is calculated as a uniform monthly rate for the rate period and does not take into account the variability of actual costs from year to year, BPA will true up the difference between the expenses and credits in the average Slice Revenue Requirement for the applicable rate period upon which the Slice rate is based and the actual expenses and credits in the Actual Slice Revenue Requirement for the applicable fiscal year. The Actual Slice Revenue Requirement for the applicable fiscal year is the sum of the final audited expenditures and revenues as reflected on BPA's Power Services financial statements, corresponding to those Power Services expense and revenue categories that are included in the Slice Revenue Requirement. BPA's financial statements contain expenses and credits that are in accordance with Generally Accepted Accounting Principles (GAAP). Any difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement is called the Slice True-Up Amount. The True-Up Amount calculation is the Actual Slice Revenue Requirement for the applicable fiscal year minus the average Slice Revenue Requirement for the applicable rate period.

A positive or negative result from the True-Up Amount calculation will result in a charge or credit to the Slice customer. The Slice True-Up Amount is then multiplied by each customer's Slice percentage to calculate the Slice True-Up Adjustment Charge (or Credit) for each customer. See section 2.15.6 for the forecast total Slice True-Up Adjustment Charges (or Credits) for FY 2010-2011. Because of the Slice True-Up Adjustment Charge (or Credit), Slice customers pay a percentage of BPA's actual costs, regardless of weather, streamflow, market, or generation output conditions. This assured payment of actual costs mitigates BPA's financial risks in the event that any adverse or beneficial conditions change BPA's financial condition. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigate the risk associated with the variability of BPA's expenses and revenue credits (for those expenses included in the Slice Revenue Requirement). The risks associated with the variability of generation output and with the uncertainty of market prices for purchasing or selling power are assumed directly by the Slice customers.

In the WP-07 Supplemental rate proceeding, BPA decided to return the FY 2002-2006 Lookback Amounts related to the REP settlement expenses as a credit on the Slice customers' power bills. BPA will ensure that Slice customers do not receive any additional payments for the return of

Lookback Amounts through the Slice True-Up process. Applicable Lookback Amounts will be returned as a credit on the Slice customers' power bills during the FY 2010-2011 period. Therefore, to ensure that Slice customers do not receive any additional payments for the return of Lookback Amounts through the Slice True-Up process for FY 2010 and FY 2011, BPA will account for these credits on Slice customers' power bills when calculating the Slice True-Up Adjustment Charge for FY 2010 and FY 2011. See the Lookback Recovery and Return Study, WP-10-FS-BPA-07 for discussions of the return of Lookback Amounts to Slice customers.

2.15.6 Forecast Slice True-Up Adjustment Charge

The Slice True-Up Adjustment Charge (or Credit) for FY 2010 and FY 2011 is forecast assuming a shift of $42 million in planned generation amortization payments to the U.S. Treasury from FY 2011 to FY 2010. See Revenue Requirement Study, WP-10-FS-BPA-02, at 3. The Slice True-Up Adjustment Credit for FY 2010 is forecast to be -$5,282,000, which is a payment from BPA to Slice customers. The Slice True-Up Adjustment Charge for FY 2011 is forecast to be $10,942,000, which is a payment from Slice customers to BPA. See Table 3.1, Slice True-Up Adjustment Charge Forecast after $42M Shift in Generation Amortization Payments to the US Treasury, WP-10-FS-BPA-05A, line 173.

2.15.7 Changes to the Methodology to Calculate Slice Rate and Slice True-Up Adjustment Charge (Slice Rate Methodology)

Several minor updates to the Slice Rate Methodology have been made to avoid confusion during FY 2010-2011. The first change is to section 4.A. Language in section 4.A. has been updated to reflect references to the FY 2010-2011 rate period. The second change is to section B.1. Language in section B.1. has been updated to reflect the reference to the two-year rate period. There are other minor changes that reflect updated references to the WP-10 rate case that occur in various places in the Slice Rate Methodology.

Table 2.5 Slice Product Costing and True-Up Table

	($000s)	Audited Actual Data	FY 2010 forecast	FY 2011 forecast
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		$ 257,811	$ 324,882
5	BUREAU OF RECLAMATION		$ 87,318	$ 96,110
6	CORPS OF ENGINEERS		$ 191,060	$ 192,433
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 30,455	$ 30,767
8	**Sub-Total**		**$ 566,644**	**$ 644,192**
9	**Operating Generation Settlement Payment**			
10	COLVILLE GENERATION SETTLEMENT		$ 21,328	$ 21,754
11	**Sub-Total**		**$ 21,328**	**$ 21,754**
12	**Non-Operating Generation**			
13	TROJAN DECOMMISSIONING		$ 2,200	$ 2,300
14	WNP-1&3 DECOMMISSIONING		$ 418	$ 428
15	**Sub-Total**		**$ 2,618**	**$ 2,728**
16	**Contracted Power Purchases**			
17	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)		$ -	$ -
18	PNCA HEADWATER BENEFITS		$ 2,042	$ 2,620
19	GROSS OTHER POWER PURCHASES (short term - omit)			
20	**Sub-Total**		**$ 2,042**	**$ 2,620**
21	**Bookout Adjustment to Power Purchases (omit)**			
22	**Augmentation Power Purchases (omit - calculated below)**			
23	AUGMENTATION POWER PURCHASES (omit)			
24	CONSERVATION AUGMENTATION (omit)			
25	**Sub-Total**		**$ -**	**$ -**
26	**Exchanges and Settlements**			
27	PUBLIC RESIDENTIAL EXCHANGE		$ 12,101	$ 10,016
28	IOU RESIDENTIAL EXCHANGE		$ 254,770	$ 258,667
29	OTHER SETTLEMENTS		$ -	$ -
30	**Sub-Total**		**$ 266,871**	**$ 268,683**
31	**Renewable Generation**			
32	RENEWABLES R&D		$ 6,174	$ 6,133
33	RENEWABLES CONSERVATION RATE CREDIT		$ 4,000	$ 2,500
34	RENEWABLES (excludes expenses from reinvested revenues)		$ 30,374	$ 30,965
35	**Sub-Total**		**$ 40,548**	**$ 39,598**
36	**Generation Conservation**			
37	GENERATION CONSERVATION R&D			
38	DSM TECHNOLOGIES		$ -	$ -
39	CONSERVATION ACQUISITION		$ 14,000	$ 14,000
40	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000
41	ENERGY EFFICIENCY DEVELOPMENT		$ 20,500	$ 20,500
42	LEGACY		$ 1,988	$ 1,622
43	MARKET TRANSFORMATION		$ 14,500	$ 14,500
44	**Sub-Total**		**$ 55,988**	**$ 55,622**
45	**Conservation and Renewable Discount (C&RD)**			
46	CONSERVATION RATE CREDIT		$ 28,000	$ 29,500
47	CONSERVATION AND RENEWABLE DISCOUNT			
48	**Sub-Total**		**$ 28,000**	**$ 29,500**
49	**Power System Generation Sub-Total**		**$ 984,039**	**$ 1,064,697**
50	**Power Services Transmission Acquisition and Ancillary Services**			
51	**Transmission Acquisition and Ancillary Services**			
52	TRANSMISSION & ANCILLARY SERVICES			
53	Canadian Entitlement Agreement Transmission Expenses		$ 27,000	$ 27,000
54	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,000	$ 1,000
55	3RD PARTY GTA WHEELING		$ 50,690	$ 51,340
56	3RD PARTY TRANS & ANCILLARY SVCS			
57	GENERATION INTEGRATION		$ 6,800	$ 6,800
58	TELEMETERING/EQUIP REPLACEMT		$ 50	$ 50
59	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 85,540**	**$ 86,190**

Table 2.5 continued, Slice Product Costing and True-Up Table

	($000s)	Audited Actual Data	FY 2010 forecast	FY 2011 forecast
60				
61	**Power Non-Generation Operations**			
62	**System Operations**			
63	SYSTEM OPERATIONS R&D		$ -	$ -
64	EFFICIENCIES PROGRAM (excludes TMS expenses)		$ -	$ -
65	INFORMATION TECHNOLOGY		$ 6,318	$ 6,282
66	GENERATION PROJECT COORDINATION		$ 7,290	$ 7,542
67	SLICE IMPLEMENTATION (omit - calculated separately)			
68	**Sub-Total**		**$ 13,608**	**$ 13,824**
69	**Scheduling**			
70	SCHEDULING R&D			
71	OPERATIONS SCHEDULING		$ 9,317	$ 9,564
72	OPERATIONS PLANNING		$ 5,808	$ 5,874
73	**Sub-Total**		**$ 15,125**	**$ 15,438**
74	**Marketing and Business Support**			
75	SALES & SUPPORT		$ 16,699	$ 17,885
76	Contractual exclusion		$ (5,360)	$ (5,360)
77	Implementation Expense Exclusions - Add back			
78	PUBLIC COMMUNICATION & TRIBAL LIAISON			
79	STRATEGY, FINANCE & RISK MGMT		$ 16,870	$ 17,343
80	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 2,546	$ 2,727
81	CONSERVATION SUPPORT (EE staff costs)		$ 11,356	$ 12,003
82	**Sub-Total**		**$ 42,111**	**$ 44,598**
83	**Power Non-Generation Operations Sub-Total**		**$ 70,844**	**$ 73,860**
84	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
85	**BPA Fish and Wildlife (includes F&W Shared Services)**			
86	FISH & WILDLIFE		$ 215,000	$ 236,000
87	**Sub-Total**		**$ 215,000**	**$ 236,000**
88	**USF&W Lower Snake Hatcheries**			
89	USF&W LOWER SNAKE HATCHERIES		$ 23,600	$ 24,480
90	**Planning Council**			
91	PLANNING COUNCIL		$ 9,683	$ 9,934
92	**Environmental Requirements**			
93	ENVIRONMENTAL REQUIREMENTS		$ 300	$ 300
94	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 248,583**	**$ 270,714**
95	**General and Administrative/Shared Services**			
96	**Additional Post-Retirement Contribution**			
97	ADDITIONAL POST-RETIREMENT CONTRIBUTION		$ 15,447	$ 15,579
98	**BPA Internal Support - G&A and Shared Srv. (excludes direct project support)**			
99	AGENCY SERVICES G&A		$ 49,961	$ 50,064
100	**Sub-Total BPA Internal Support Services**		**$ 49,961**	**$ 50,064**
101	**Supply Chain - Shared Services**			
102	**General and Administrative/Shared Services Sub-Total**		**$ 65,408**	**$ 65,643**
103	**Bad Debt Expense**		$ -	$ -
104	**Other Income, Expenses, Adjustments**		**$ -**	**$ -**
105	**Non-Federal Debt Service**			
106	**Energy Northwest Debt Service**			
107	COLUMBIA GENERATING STATION DEBT SVC		$ 235,736	$ 226,169
108	WNP-1 DEBT SVC		$ 166,013	$ 167,549
109	WNP-3 DEBT SVC		$ 144,892	$ 169,093
110	EN RETIRED DEBT			
111	EN LIBOR INTEREST RATE SWAP			
112	**Sub-Total**		**$ 546,641**	**$ 562,811**
113	**Non-EN Debt Service**			
114	COWLITZ FALLS DEBT SVC		$ 11,566	$ 11,563
115	N. WASCO DEBT SVC		$ 2,200	$ 2,196
116	TROJAN DEBT SVC		$ -	$ -
117	CONSERVATION DEBT SVC		$ 5,079	$ 4,924
118	**Sub-Total**		**$ 18,845**	**$ 18,683**
119	**Non-Federal Debt Service Sub-Total**		**$ 565,486**	**$ 581,494**
120	**Depreciation (excludes TMS)**		$ 120,111	$ 121,235
121	**Amortization (excludes ConAug amortization)**		$ 64,392	$ 72,363
122	**Total Operating Expenses**		**$ 2,204,403**	**$ 2,336,196**

Table 2.5 continued, Slice Product Costing and True-Up Table

($000s)

		Audited Actual Data	FY 2010 forecast	FY 2011 forecast	
123					
124	**Other Expenses**				
125	Net Interest Expense		$ 167,119	$ 173,301	
126	LDD		$ 26,419	$ 26,465	
127	Irrigation Rate Mitigation Costs		$ 12,036	$ 12,036	
128	**Sub-Total**		**$ 205,574**	**$ 211,802**	
129	**Total Expenses**		**$ 2,409,977**	**$ 2,547,998**	
130					
131	**Revenue Credits**				
132	Ancillary and Reserve Service Revs. Total		$ 90,176	$ 102,730	
133	Downstream Benefits and Pumping Power		$ 8,921	$ 8,921	
134	4(h)(10)(c)		$ 96,689	$ 101,969	
135	Colville and Spokane Settlements		$ 4,600	$ 4,600	
136	FCCF				
137	Energy Efficiency Revenues		$ 20,500	$ 20,500	
138	Miscellaneous		$ 3,420	$ 3,420	
139	Green Tag revenue associated with Klondike III		$ -	$ -	
140	Ad Hoc revenue credit adjustment				
141	**Total Revenue Credits**		**$ 224,306**	**$ 242,140**	
142	**Augmentation Costs (not subject to True-Up)**				
143	**Non-DSI Net Augmentation Costs**				
144	Gross Augmentation cost (72.7 aMW, 274.7 aMW)		$ 26,019	$ 108,375	
145	Minus revenues 70.7 aMW, 267.1 aMW @ PF rate		$ (17,815)	$ (67,325)	
146			**$ 8,204**	**$ 41,050**	
147	**DSI Net Augmentation Costs**				
148	Gross Augmentation cost (413 aMW, 413 aMW)		$ 154,746	$ 164,668	
149	Minus revenues 402 aMW, 402 aMW @ IP rate		$ (121,852)	$ (121,852)	
150			**$ 32,895**	**$ 42,815**	
151					
152	**Total Net Cost of Augmentation**		**$ 41,099**	**$ 83,865**	
153					
154					
155	**Minimum Required Net Revenue calculation**				
156	Principal Payment of Fed Debt for Power		$ 202,673	$ 204,163	
157	Irrigation assistance		$ -	$ -	
158	Depreciation		$ 120,111	$ 121,235	
159	Amortization		$ 77,728	$ 85,699	
160	Capitalization Adjustment		$ (45,937)	$ (45,937)	
161	Bond Premium Amortization		$ 185	$ 185	
162	Principal Payment of Fed Debt exceeds non cash expenses		$ 50,586	$ 42,981	
163	Minimum Required Net Revenues		**$ 50,586**	**$ 42,981**	
164					**2-Year Total Rev**
165	Annual Slice Revenue Requirement (Amounts for each FY)		**$ 2,277,356**	**$ 2,432,704**	**$ 4,710,060**
166					
167	SLICE TRUE-UP ADJUSTMENT CALCULATION				
168					
169	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case		**$ 2,355,030**		
170	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)				
171	AMOUNT BILLED (22.6278 percent)				
172	Slice Implementation Expenses (not incl. in base rate)				
173	TRUE UP ADJUSTMENT				
174					
175					
176	**SLICE RATE CALCULATION ($)**				
177	**Monthly Slice Revenue Requirement (2-Year total divided by 24 months)**				**$ 196,252,520**
178	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,962,525**
179					
180	**ANNUAL BASE SLICE REVENUES**				**$ 532,891,534**
181	**Annual Slice Implementation Expenses**				**$ 2,830,000**
182	**TOTAL ANNUAL SLICE REVENUES**				**$ 535,721,534**

3. COST ALLOCATION AND RATE DESIGN IMPLEMENTATION

3.1 Ratemaking Sequence

BPA’s power ratemaking methodology includes a Cost of Service Analysis (COSA), a series of Rate Design Step adjustments, and a Slice Product Separation Step. The COSA assigns responsibility for BPA’s power revenue requirement to the various classes of service in compliance with statutory directives governing BPA’s ratemaking and in accordance with generally accepted ratemaking principles. The Rate Design Step adjustments to the allocated costs derived in the COSA are necessary to ensure that BPA recovers its rate period revenue requirement while following its statutory rate directives. The Slice Product Separation Step separates out the PF Preference Slice product firm loads, allocated costs, and allocated revenue credits from the overall PF Preference loads, allocated costs, and allocated revenue credits. These ratemaking steps are programmed into a spreadsheet model, the Rate Analysis Model (RAM2010), for purposes of calculating power rates.

3.2 Cost of Service Analysis

The COSA allocates the rate period power revenue requirement determined in the Revenue Requirement Study, WP-10-FS-BPA-02, to customer classes. The COSA first groups parts of the power revenue requirement into cost pools specified by section 7 of the Northwest Power Act. The cost pools are associated with resource pools (Federal base system resources, exchange resources, and new resources) and costs allocated according to section 7(g) of the Northwest Power Act. The COSA then apportions or “allocates” the cost pools among classes of service (also known as rate pools or load pools) based on the priorities of service from resource pools to rate pools provided in section 7, and the principle of cost causation when section 7 does not provide guidance. The relative use of resources, services, and facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use.

Functionalization of costs between power and transmission is performed in the development of the total generation revenue requirement, and only those costs are included in power rates. One exception to this is exchange resource costs, which are functionalized so that only the power portion of the exchange resource costs is subject to the power cost rate design steps, and the transmission cost portion is then added back in after the rate design steps are completed.

3.2.1 Power Services 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 requires 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.

The Revenue Requirement Study, WP-10-FS-BPA-02, is based on power revenue and cost estimates for a two-year rate period, FY 2010-2011. A preliminary power revenue requirement from the Revenue Requirement Study is adjusted in the COSA for costs that are determined in other steps of the ratemaking process: projected balancing purchase power costs, system augmentation costs, PNRR, and the functionalized exchange resource costs. The adjusted annual functionalized revenue requirements used for rate calculations are shown in COSA tables of the Documentation, WP-10-FS-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06 FY 2010 and COSA 06 FY 2011). The functionalization of exchange resource costs is shown in Table 2.3.3 (COSA 07). The total adjusted functionalized revenue requirement for the two-year period is shown in

Table 2.3.4 (COSA 08). The adjustments to the preliminary power revenue requirement are then incorporated into the ultimate power revenue requirement.

3.2.1.1 Revenue Requirement Study

In compliance with Commission order *U.S. Department of Energy–Bonneville Power Admin.*, 26 FERC ¶ 61,096 (January 27, 1984), a power repayment study specifically for the power function is prepared. All costs that are functionalized to power are used to develop the power revenue requirement in this Final Proposal.

The Revenue Requirement Study, WP-10-FS-BPA-02, also includes demonstrations to show that revenue from the proposed rates is adequate to recover all power-related costs of the FCRPS in the rate period and over the repayment period (the revised revenue test).

3.2.1.2 Power Purchases in the COSA

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

3.2.1.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power are included in the new resources resource pool. Documentation, WP-10-FS-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

3.2.1.2.2 Balancing Power Purchases

The costs of power purchases and storage required to meet firm deficits on a daily and monthly basis are included in the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads in months other than the spring fish migration period under some water conditions. The cost is the expected value of balancing power purchase costs under 70 different water conditions. The expense estimate for balancing power purchases included in the preliminary power revenue requirement is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. Documentation, WP-10-FS-BPA-05A, Tables 4.8.2 and 4.8.3. Balancing power purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. Documentation, WP-10-FS-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

3.2.1.2.3 System Augmentation

For ratesetting purposes, it is assumed that BPA must acquire an amount of resources beyond the inventory represented by the system generating resources and balancing power purchases. These acquisition amounts are determined in the Loads and Resources Study, WP-10-FS-BPA-01, and are used to meet annual customer firm power loads in excess of annual firm system resources. The cost of system augmentation purchases is estimated using prices under 1937 water conditions. The expense estimate for system augmentation purchases included in the preliminary power revenue requirement is adjusted in the COSA. The adjustment is based on the application of market prices under the 1937 water condition from the 70 water year price forecast to the amount of system augmentation determined in the Loads and Resources Study. Market Price Forecast Study, WP-10-FS-BPA-03, section 2.5. System augmentation purchases are treated as FBS replacements, and as such, the costs are included in and allocated as FBS costs. Documentation, WP-10-FS-BPA-05A, Tables 2.3.1 and 2.3.2 (COSA 06).

3.2.2 Functionalization of Exchange Resource Costs

In the COSA, exchange resource costs are based on participating utilities' ASCs and their exchange sales to BPA. ASCs include the cost of power and transmission services associated with serving a participating utility's total retail load. See section 6. By statute, exchange resource sales to BPA equal the exchange sales by BPA and both are determined by the amount of the utility's qualifying exchange load. The rate design adjustments that follow the COSA in BPA's ratemaking use the results of the COSA allocations of the power revenue requirement. Therefore, because the exchange resource costs in the COSA include transmission costs, 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 power revenue requirement for the rate design steps and then are added back to the PF Exchange rate after all of the rate design steps have been accomplished. In this way, the exchange resource costs functionalized to power are treated the same as other power function costs through the rate design adjustment process. The functionalization of exchange resource costs is shown in the Documentation, WP-10-FS-BPA-05A, Table 2.3.3 (COSA 07).

3.2.3 Classification

Classification is the process of apportioning power costs among the components of electric power, usually demand, energy, and other costs. BPA discontinued traditional classification in 1996, replacing it with marginal cost-based ratemaking. As a result of this change, costs classified to demand and load variance are based on the expected revenue from marginal cost-based demand and load variance rates. These revenues are subtracted from the power revenue requirement to determine the costs classified to energy. This classification of the power revenue requirement is shown for informational purposes only in the Documentation, WP-10-FS-BPA-05A, Table 2.3.4 (COSA 08). All power costs are allocated to rate pools based on energy allocation factors. See section 3.2.5.2.

The monthly demand rates are scaled upward from the FY 2009 demand rates, as described in section 2.4.2. The load variance rate is scaled upward from the FY 2009 load variance rate, as described in section 2.4.5. The scaled demand and load variance rates are multiplied by forecast sales under these rates to determine expected revenues for demand and load variance. The costs classified to demand and load variance are deemed to be equal to the revenues from demand and load variance. Power costs classified to energy are the residual total power costs not classified to demand or load variance. After all allocation and rate design steps, the classification is applied by subtracting the revenues forecast to be recovered from demand and load variance rates from the overall costs allocated to each rate pool, and the energy rates collect the remainder.

3.2.4 Functionalized and Classified Revenue Credits

The revenue credits described below are functionalized to power. Most 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.

3.2.4.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues include payments from the sale of Reserve Energy and Irrigation Pumping Power. They also include revenues from owners of projects downstream to the COE and Reclamation projects for benefits received (i.e., additional generation due to releases from the storage reservoirs owned by the COE and Reclamation). Reserve Energy and Irrigation Pumping Power revenues are earned through the year and are paid at the end of the year directly to the U.S. Treasury by the COE and Reclamation. These revenues are not subject to revision through BPA's rate process and hence become a revenue credit. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

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

Section 4(h)(10)(C) credits are available from the U.S. Treasury to compensate BPA for its direct program fish and wildlife expense and capital costs, and hydro system operational costs incurred for fish migration attributable to the non-power portions of the hydro projects. These credits are currently 22.3 percent of these eligible costs. This revenue credit is an estimate of the credits BPA would receive on average over a range of 70 different water conditions. The actual credit is determined after each year is completed. The operational costs vary with water conditions. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.4.3 Colville Credit

The Colville credit is a U.S. Treasury credit BPA receives as a result of a settlement of claims associated with the development of Grand Coulee Dam. The credit is a fixed annual amount of $4.6 million that is provided through the Confederated Tribes of the Colville Reservation Grand Coulee Dam Settlement Act, Public Law No. 103-436, adopting the settlement agreement between the Confederated Tribes of the Colville Reservation and the United States of America. The Omnibus Consolidated Rescissions and Appropriations Act of 1996, Public Law 104-134, amended section 6 of the Settlement Act to provide BPA with a credit of $4.6 million against its annual payment to the United States Treasury for fiscal year 2002 and each succeeding fiscal year. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.4.4 Energy Efficiency Revenues

This credit reflects revenues associated with the activities of BPA's Energy Efficiency program. These revenues are generally payments for reimbursible expenditures that are included in the power 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. Documentation, WP-10-FS-BPA-05A, Table 2.3.6 (COSA 09A).

3.2.4.5 Miscellaneous Revenues

This credit represents estimated revenues from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change through BPA's rate process. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.4.6 Reserve Product Revenues

Reserve product revenues result from the sale of products and services provided under the FPS rate schedule to customers outside the BPA BAA and may include supplemental automatic generation control, spinning reserves, supplemental reserves, and forced outage reserves. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.4.7 Green Energy Premium Revenues

Green Energy Premiums result from BPA's sales of Environmentally Preferred Power and renewable energy certificates. The revenue amounts depend on actual wind and renewable project output included in the FBS. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.4.8 Power Services Ancillary and Reserve Services 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, WP-10-FS-BPA-08, explains and documents these credits. These revenues have the effect of reducing the FBS resource costs to be recovered by power rates. The expected generation inputs credits are $90.176 million for FY 2010 and $102.730 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 2.3.5 (COSA 09).

3.2.5 Allocation

Allocation is the apportionment of costs to rate pools or customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools, pursuant to the rate directives contained in section 7 of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act, specifically the FBS, exchange, and new resources resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation. The sizes of the rate and resource pools are determined based on the results of the Loads and Resources Study, WP-10-FS-BPA-01.

Rate pools are groupings of customer classes (expressed as sales) for cost allocation purposes. The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes public body, cooperative, and Federal agency sales and sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers under contracts authorized by section 5(d). The 7(f) rate pool includes all power BPA sells pursuant to section 5(f). Subsequent to 1985 and implementation of the directives of section 7(c)(2) 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 FBS resource pool consists of the costs of the following resources: (1) the 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 resource types. Costs expected to be incurred during the rate period for FBS replacement resources are included in the FBS resource cost pool. See sections 3.2.1.2.2 and 3.2.1.2.3.

3.2.5.1 Power Cost Allocations

The process of allocating power costs begins with an examination of critical period firm loads and resources. A ratemaking load-resource balance for each year of the rate period is then constructed from the Loads and Resources Study, WP-10-FS-BPA-01, and other data. From this ratemaking load-resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate period. Table 2.4.1 (ALLOCATE 01) of the Documentation, WP-10-FS-BPA-05A, shows the ratemaking energy loads and resources by pools.

As shown in Table 3.1 below, allocation is based on matching service from each resource pool to each rate pool. The FBS resource pool is first used to serve the 7(b) rate pool. When the FBS resource pool is exhausted, the exchange resource pool is used to serve the 7(b) rate pool. If the combined FBS and exchange resource pools are insufficient to fully serve the 7(b) resource pool, then the new resources resource pool is used. If the exchange resource pool is not fully exhausted in serving the 7(b) rate pool, any remaining exchange resources are used to serve the "all other" rate pool; otherwise, the "all other" rate pool is served entirely from the new resources resource pool.

Table 3.1
Summary of Resource Pool Service to Rate Pools

Resource Pool	FY 2010 7(b) Pool	FY 2010 All Other Pool	FY 2011 7(b) Pool	FY 2011 All Other Pool
FBS	8,205		8,181	
Exchange	3,567	1002	3,652	969
New Resources		108		108
Total Usage	11,772	1,110	11,833	1,077

3.2.5.2 Energy Allocation Factors

When service from each resource pool to each rate pool has been identified, the amounts of such service are the allocation factors for the costs of the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Documentation, WP-10-FS-BPA-05A, Table 2.4.1 (ALLOCATE 01). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, Exchange, and New Resources allocation factors. They are used to allocate section 7(g) costs and rate design allocation adjustments to all firm energy loads. Allocated power costs are shown in the Documentation, WP-10-FS-BPA-05A, Table 2.4.2 (ALLOCATE 02).

3.2.5.3 Other Cost Allocations

Power costs not directly identifiable with resource pools are allocated as described in the following sections.

3.2.5.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation savings as an electric power resource in planning to meet the Administrator's obligations to serve loads. The "conservation" line item, as seen in the COSA 06 tables (Documentation, WP-10-FS-BPA-05A, Tables 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; (4) costs associated with the Conservation Rate Credit; and (5) a share of Net Revenues. The "Energy Efficiency" revenue line item in Table 2.3.6 (COSA 09A) reflects payments provided by utilities, other organizations, and Federal agencies for the energy efficiency services delivered. Energy Efficiency revenues are credited against BPA's conservation costs, and the conservation costs that are net of these revenues continue though the remaining ratemaking process. Documentation, WP-10-FS-BPA-05A, Table 2.3.6 (COSA 09A). Section 7(g) of the Northwest Power Act directs that the costs of conservation be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Conservation costs are allocated to all rate pools using the Conservation energy allocation factors.

3.2.5.3.2 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 the ratemaking process. The power portion of these program costs is determined in the Revenue Requirement Study, WP-10-FS-BPA-02. The power portion appears in the COSA as BPA program costs. Section 7(g) of the Northwest Power Act directs that all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. BPA program costs are allocated to all rate pools based on the Total Usage energy allocation factors. Documentation, WP-10-FS-BPA-05A, Table 2.3.4 (COSA 08).

3.2.5.3.3 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 BPA's ratemaking methodology, the amount of PNRR is the result of an iterative process between the RAM2010, RiskMod, Non-Operating Risk Model (NORM), and ToolKit models. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, Section 4. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM2010. The resultant rates are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value for new COSA 06 tables. Documentation, WP-10-FS-BPA-05A, section 2. Because the PNRR is determined to be zero, no iterative process is required to determine rate levels for this Final Proposal.

In the case when there is an amount of PNRR needed, the PNRR value is combined with any minimum required net revenue. The sum of Net Revenues is found in the COSA 06 tables. Section 7(g) of the Northwest Power Act directs that the costs of the sale of or inability to sell excess electric power (a major component of PNRR) and all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Net Revenues are allocated to resource pools that include Federal capital investments (FBS, Conservation, and BPA Program) using net interest cost assignment.

3.2.5.3.4 Transmission Costs

Transmission costs include the costs of serving transfer service customers with Federal power provided 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 PNW. Section 7(g) of the Northwest Power Act directs that all costs and benefits not otherwise allocated under section 7 be equitably allocated to power rates in accordance with generally accepted ratemaking principles. Transmission costs are allocated to all rate pools based on the Total Usage energy allocation factors. Documentation, WP-10-FS-BPA-05A, Table 2.3.4 (COSA 08).

3.2.6 COSA Results

Table 2.4.2 (ALLOCATE 02) of the Documentation, WP-10-FS-BPA-05A, summarizes the allocations of the power revenue requirement to classes of service.

3.3 Rate Design Step Adjustments

Rate design adjustments are performed sequentially and iteratively in the order described in this section.

3.3.1 Secondary and Other Revenues

The Secondary and Other Revenues adjustment recognizes that BPA collects revenues from certain classes of service to which costs are not allocated. BPA credits these revenues to classes of service served with firm Federal power. Projected secondary energy sales are the largest source of revenue credits.

3.3.1.1 Secondary Energy Sales

For resource planning purposes and to determine the amount of system augmentation, the ratemaking process requires that the forecast of firm resources available be equal to firm load obligations under critical water conditions. However, rates are set assuming that better than critical water conditions will occur. BPA projects secondary energy sales and revenues in RiskMod using 70 historical water years. The projected secondary energy revenue credits are included so that BPA does not set power rates to recover more than its revenue requirement.

RiskMod projects the level of secondary energy sales and revenues, as discussed in the Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, Section 2. The FCRPS is expected to generate secondary energy that will produce about $703.9 million in revenues in FY 2010 and $767.6 million in FY 2011. Of the rate period total of $1,471.5 million in forecast secondary revenue, $373.5 million is allocated pursuant to section 7(b)(3) to the recovery of section 7(b)(2) rate protection. The remaining $1,098.0 million is allocated as a revenue credit. 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 the allocation pursuant to section 7(b)(3) are allocated to rate pools based on the FBS energy allocation factors. Documentation, WP-10-FS-BPA-05A, Table 2.5.3 (RDS 11). In one of the last ratemaking steps, the Slice Separation Step, 22.63 percent of the $1,471.5 million in forecast secondary revenue for the rate period, or about $333.0 million, is assumed to be sold to BPA's Slice product customers, reducing the revenue credit allocated to the PF Preference rate. Documentation, WP-10-FS-BPA-05A, Table 2.6.1 (SLICESEP 01).

3.3.1.2 Other Revenue Credits

BPA receives revenue from miscellaneous sources and from miscellaneous power sales. These revenue credits are allocated as described in section 3.2.4. For FY 2010, the forecast revenue from these sources is $210.8 million, and for FY 2011, $228.6 million. Documentation, WP-10-FS-BPA-05A, Table 2.5.3 (RDS 11).

3.3.2 Firm Power Revenue Deficiencies Adjustment

BPA sells firm power at contractual rates and in the open market under the FPS rate schedule. The COSA includes these sales in the 7(f) rate pool and allocates costs to these sales. Sales of such firm power are not necessarily made at the fully allocated cost of the power. 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 sale of such power. In the FY 2010-2011 rate period, revenue of $256.9 million is forecast from the sale of firm power in PNW and Southwest markets. Documentation, WP-10-FS-BPA-05A, Table 2.5.4 (RDS 17). The COSA allocates $688.8 million in power costs to this firm power. Therefore, there is a revenue deficiency of $431.9 billion over the two-year rate period. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates. Documentation, WP-10-FS-BPA-05A, Table 2.5.4 (RDS 17).

3.3.3 Rate Discount Costs

Section 7(d) allows BPA to apply discounts to the rates of customers with low system densities. See section 2.10. In addition, BPA offers the IRMP to allow discounted power sales for irrigation loads. See section 2.9. The revenues collected through PF Preference rate sales after these discounts are applied will be lower than allocated to the PF Preference class of service. Therefore, an estimate of the revenue discounts is added to the costs allocated to the PF class of service. Documentation, WP-10-FS-BPA-05A, Table 2.5.5 (RDS 19). The costs of the CRC are already included in the power revenue requirement, so no further adjustment is necessary.

3.3.4 7(c)(2) Adjustment

DSI ratesetting 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." Pursuant to section 7(c)(2), the IP rate is to be based 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 IP 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. Thus, the IP rate is set equal to the applicable wholesale rate, plus the typical margin, minus the VOR credit, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. See sections 3.3.4 and 3.3.5 below for additional explanation.

The applicable wholesale rate is the weighted average of (1) the PF rate and (2) the NR rate sales to COU NLSLs (none of the latter are projected for the rate period) at the DSI load factor. The typical margin is based generally on the overhead costs that COUs add to BPA's price of power in setting their retail industrial rates. The typical margin is 0.636 mills/kWh and is determined by applying a GDP inflation adjustment to the 0.573 mills/kWh typical margin established in the WP-07 Final Proposal. A VOR credit to the IP rate of 0.80 mills/kWh has been calculated as the value of reserves provided by the DSIs, shown in section 2.2.1. The typical margin minus the VOR credit yields the net margin of negative 0.164 mills/kWh. This negative net margin is added to the monthly diurnal PF energy rates. These adjusted energy rates and the demand rates are applied to the DSI rate period billing determinants to determine the final IP rate.

The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the final IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI customers, primarily the PF customers. However, the allocation of this 7(c)(2) Delta then changes the PF rate, the rate upon which the IP rate is based, and the 7(c)(2) Delta must be recalculated. The interaction between the PF rate and the IP rate has been reduced to an algebraic solution. Documentation, WP-10-FS-BPA-05A, Table 2.5.6 (RDS 21).

3.3.5 7(b)(2) Adjustment

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06. If the 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency 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). 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 due to the rate protection, the PF rate is bifurcated. The two resulting rates are the PF Preference 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 section 7(b)(3) Supplemental Rate Charges applied to all non-PF Preference sales. A further calculation is performed to determine utility-specific 7(b)(3) Supplemental Rate Charges for utilities participating in the Residential Exchange Program. Documentation, WP-10-FS-BPA-05A, Table 2.9 (REP 1).

The Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06, indicates that the 7(b)(2) rate test has triggered, and thus the PF rate applicable to BPA's COU customers, the PF Preference rate, is adjusted downward. Subsequent to the section 7(b)(2) rate test, three adjustments in the rate design steps sequence provide this rate protection to COU customers and reallocate the rate protection.

First, the PF Preference customer class is allocated a credit, which reduces its rate, in the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06. The rate protection amounts to 8.17 mills/kWh, for a rate period reduction of about $1,003.4 million to the allocated costs for the PF Preference customer class. This protection is reallocated to all other sales. Because the rate protection is allocated in part to surplus power sales, the secondary revenue credit is reduced as described in section 3.3.1.1. This reduction introduces a necessary iteration to solve the interaction between the secondary revenue credit and the rate protection amount. Documentation, WP-10-FS-BPA-05A, Table 2.5.9 (RDS 30).

3.3.6 7(b)(2) Industrial Adjustment 7(c)(2) Delta

The second adjustment is the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. The amount of this adjustment is the value of a recalculated 7(c)(2) Delta at the lower PF Preference rate that results from the allocation of the 7(b)(2) rate protection to the PF Preference rate. The same adjustments described in the 7(c)(2) Adjustment, section 3.3.4, are performed again with the lower PF Preference rate, except that the reallocated amounts are not allocated to the PF Preference rate. Documentation, WP-10-FS-BPA-05A, Table 2.5.10 (RDS 33).

3.3.7 REP Deemer Adjustment

A utility in deemer status has an ASC lower than the PF Exchange rate. To eliminate the necessity for such an exchanging utility to pay BPA the difference, its ASC is deemed equal to the PF Exchange rate. If it had been forecast that an exchanging utility was in deemer status, a third adjustment would be necessary to allocate an increase in the exchange resource costs resulting from the increase of the deeming utility's ASC to equal the PF Exchange rate, which results from the reallocation of the 7(b)(2) rate protection. A utility's exchange resource costs up to this point are calculated prior to the 7(b)(2) rate test using a lower PF Exchange rate as its ASC. Now, with the higher PF Exchange rate, the utility's ASC is higher than before the reallocation of the rate protection. Therefore, the increase in exchange resource costs must be recalculated. Any increase in the exchange resource costs can be allocated only to the PF Exchange rate and the NR rate. Because no exchanging utility is forecast to be in deemer status, this rate adjustment is not necessary.

3.3.8 DSI Floor Rate Test

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. Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate (the floor 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 2010 and FY 2011) DSI billing determinants. The resulting revenue figure is divided by total IP rate period energy loads to arrive at an average rate in mills/kWh. 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/kWh 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/kWh from the IP-83 rate in the same manner that the Exchange Cost Adjustment and Deferral Adjustment are removed. The mills/kWh 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.

These calculations result in an undelivered DSI floor rate of 20.98 mills/kWh. The floor rate is applied to the rate period DSI billing determinants to determine floor rate revenue. Revenue at the proposed IP rates is compared to revenue at the floor rate. Because the proposed IP rate revenue is greater than the floor rate revenue, no floor rate adjustment is necessary to the IP rate. Documentation, WP-10-FS-BPA-05A, Tables 2.5.7 (RDS 23) and 2.5.8 (RDS 24), for the DSI floor rate calculation. The final Rate Design Step cost allocations are shown in the Documentation, Table 2.5.10 (RDS 33).

3.4 Slice Cost Calculation

Slice customers assume the obligation to pay a percentage of BPA's costs, rather than a predetermined rate per kilowatt or kilowatthour. See section 2.15. A Slice customer's obligation to pay is equal to the percentage of the FCRPS that the Slice customer elects to purchase. The costs considered by the Slice contract are referred to collectively as the Slice Revenue

Requirement. The Slice Revenue Requirement is comprised of all of the line items in the power revenue requirement, with certain limited exceptions. The calculation of the cost of the Slice product for FY 2010 and FY 2011 in dollars per month for each percent of the Federal system is shown in the Documentation, WP-10-FS-BPA-05A, Table 2.13.1 (Slice Cost Table).

3.5 Slice PF Product Separation Step

After the COSA and Rate Design steps, costs allocated to the 7(b) rate pool have been bifurcated to the PF Preference class of service (all firm PF Preference load) and PF Exchange class of service. The Slice Separation Step separates out the PF Slice product revenues, firm loads, and revenue credits from those allocated to the entire PF Preference class of service, leaving the costs that must be recovered from the remaining non-Slice PF Preference load through the PF Preference energy, demand, and load variance rates. Documentation, WP-10-FS-BPA-05A, Table 2.6.1 (SLICESEP 01).

3.5.1 7(c)(2) Non-Slice PF Adjustment

After the Slice PF Product Separation Step, the PF Preference rate level may have changed, necessitating a third 7(c)(2) adjustment. This final rate adjustment sets the final IP rate equal to the non-Slice PF rate at the DSI load factor, plus the net industrial margin, plus any 7(b)(3) Supplemental Rate Charge. Documentation, WP-10-FS-BPA-05A, Table 2.6.2 (SLICESEP 02).

3.6 Rate Analysis Results

The rate modeling described above results in an average PF-10 Preference rate of 28.77 mills/kWh, an average IP-10 rate of 34.60 mills/kWh, an average NR-10 rate of 68.67 mills/kWh, and a load-weighted average PF Exchange rate of 48.68 mills/kWh. Documentation, WP-10-FS-BPA-05A, Tables 2.7, 2.10, 2.11, and 2.9A. The rate modeling produces the actual component rates of the PF-10, IP-10, and NR-10 rate schedules.

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4. REVENUE AND PURCHASE POWER EXPENSE FORECAST

This section describes the revenue forecast and purchase power expenses prepared for the WP-10 Final Proposal and presents the results of that forecast for FY 2009, FY 2010, and FY 2011.

4.1 Overview

The revenue forecast presents the expected level of sales and revenue from power rates and other sources for the rate period, FY 2010-2011. Two revenue forecasts are prepared. One uses current rates, and the other uses proposed rates. These forecasts are used to test whether current rates will recover the power revenue requirement and whether proposed rates are sufficient to recover the revenue requirement. The revenue test is described in the Revenue Requirement Study, WP-10-FS-BPA-02, section 4.1.1. The power rates placed in effect October 1, 2008, are used in the calculation of revenue at current rates for FY 2010-2011, using the load forecast in the Loads and Resources Study, WP-10-FS-BPA-01.

The proposed rates are applied to the same loads to create a revenue forecast at proposed rates for FY 2010-2011. The revenue from this forecast is shown in the Documentation, WP-10-FS-BPA-05A, Table 4.6.2.

4.2 Revenue Forecast Methodology

The first step in developing the revenue forecast is to apply rates to the forecast of firm sales. Long-term contracts contain confidential information, so the revenues calculated for individual contracts are summed and added to the forecast as a group. The sales forecast to be made under regional pre-Subscription FPS contracts are multiplied by the specific contract rates. Because these contracts contain confidential information, the billing determinants and revenues are totaled. The revenues are reported for HLH energy, LLH energy, demand, and load variance. Some of these contracts have only HLH and LLH energy billing determinants and one, Canadian Entitlement Return, represents an obligation for which no revenue is received. Documentation, WP-10-FS-BPA-05A,Tables 4.6.1 and 4.6.2.

Subscription power sales billing determinants from the sales forecasts are applied to the appropriate set of PF rates to calculate BPA's expected revenue from these contracts. Revenues from long-term contract sales are calculated by applying the contract rates to these contracts in the same manner as the revenues are calculated from pre-Subscription contracts. These contracts also contain confidential information; therefore, the contract revenues are summed and displayed grouped. Generation inputs for ancillary services and other services and inter-business line cost allocations are added to the power revenues.

4.2.1 Other Factors Affecting Forecast Revenues

Other factors affecting forecast revenues include the LDD and Irrigation Rate Mitigation sales, which are described below.

4.3 Power Sales Forecast

The proposed sales forecast used in the revenue forecast is the source of energy and demand billing determinants used to calculate rates and revenues. The energy load forecasts include forecast energy loads of PF, IP, NR, and FPS sales. Energy load forecasts used in this rate proposal are documented in the Loads and Resources Study, WP-10-FS-BPA-01, and accompanying Documentation, WP-10-FS-BPA-01A.

The firm loads under Subscription contracts expected using current rates are the same as the firm loads expected using proposed rates. Because the same load forecast is used for both revenue forecasts, the forecasts of surplus market and other sales are also the same. The only revenues that differ between these forecasts are for PF and IP rate sales. Documentation, WP-10-FS-BPA-05A, Tables 4.6.1 and 4.6.2.

4.4 Power Revenue Forecast

Power Services' revenue comes from five sources. The first (and largest) source of revenue is the sale of firm power under Subscription (including Slice) contracts to regional public bodies and Federal agencies and to direct service industries.

The second revenue source is long-term contractual obligations, where the prices are already determined by contract or by contract formula.

The third source of revenue is short-term energy sales, where prices are determined by the market. This source includes power sold on a monthly, weekly, daily, or hourly basis. Bookouts are a common practice in the utility industry to minimize transmission expenses when deliveries of two transactions of equal size moving in opposite directions of a transmission line are cancelled out by the transacting parties. Since FY 2004, bookouts have been required by GAAP to be subtracted from both revenue and expenses, but the dollars still change hands as if the transaction occurred. In FY 2009, bookouts through December are -$24 million. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 22.

The fourth source of revenue is the sale of generation inputs to Transmission Services. The majority of this revenue comes from the sale of generation inputs to Transmission Services. See section 3.2.4.8.

The last revenue source is revenue credits from the U.S. Treasury and revenues from miscellaneous sources, such as payment for energy efficiency installations, storage fees, contract administration, contract termination and settlement fees, low-voltage delivery charges, reimbursement of transfer fees, and interest on late payments. The credits include those associated with Northwest Power Act section 4(h)(10)(C) and the Colville Settlement. The credit associated with BPA payments to the Colville Tribe for the use of reservation land for power production is fixed by statute. See section 3.2.4.3.

4.4.1 Forecast of Subscription Revenues for FY 2010 and 2011

The Subscription contracts currently in effect describe the basic products for which the Final Proposal PF rates are designed. Most of BPA's firm power will be sold under these contracts. The revenue from these contracts is estimated by applying the current and proposed PF rates to the projected billing determinants. The LDD also is applied to eligible loads. The Conservation Rate Credit (CRC) included in the PF rate schedules is reflected in Power Services' expenses rather than in the revenues. Current PF rates applied to these sales yield revenue of $1,720 million for FY 2010 and $1,753 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, lines 5 and 7. Proposed rates applied to these sales yield revenue of $1,831 million for FY 2010 and $1,850 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2, lines 5 and 7.

4.4.1.1 Low Density Discount (LDD)

The calculation of the LDD for a representative but unidentified customer is shown in Table 4.10 of the Documentation, WP-10-FS-BPA-05A. The calculation is compared to the output from the Revenue Forecast Application (RFA) database to demonstrate how the LDD calculations are performed.

4.4.1.2 Irrigation Rate Mitigation Sales

The Irrigation Rate Mitigation Product provides sales to irrigation loads that total 196 aMW for FY 2009, 191 aMW for 2010, and 190 aMW for 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 9. The revenue from these Irrigation Rate Mitigation sales is based on contractually specified FPS rates that are lower than the PF rate but change by the amount of the base PF rate change.

4.4.2 Contract Formula Rates

Some of BPA's contracts include specified formulas for calculating rates. These rates are based on a variety of factors, including changes in the PF rate and changes in the BPA Average System Cost (BASC). Contracts that could be in either sale or power exchange mode are assumed to be in the exchange mode for FY 2010 through FY 2011, or until the contracts expire. Revenue from Power Services in-region and out-of-region long-term contract sales at current rates is forecast to total $162 million for FY 2010 and $155 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, lines 8, 9, 11, and 17.

4.4.3 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. The surplus energy revenue included in the revenue forecast is the average of the surplus energy revenues computed for each of 70 historical water years. This power is sold under the FPS rate schedule.

Short-term market sales are computed using RiskMod to calculate monthly HLH and LLH energy surpluses for each of the 70 water years, applying corresponding market prices for each water condition. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, section 2.1.

The results of the 70 water year run of RiskMod and the resulting short-term market sales and corresponding revenues are $545 million for FY 2010 and $594 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.8.1.

4.4.4 Section (4)(h)(10)(C) Credits and Colville Settlement

RiskMod also produces the average annual section 4(h)(10)(C) operational credits that BPA can claim when making its annual U.S. Treasury payments. See Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, section 2, and Documentation, WP-10-FS-BPA-05A, Summary Table 4.6.1, line 15. These average annual values are derived by estimating the amount of section 4(h)(10)(C) operational credits that BPA could claim under each of the 70 historical streamflow conditions and then adding them to the other 4(h)(10)(C) credits BPA will receive.

The additional purchased power costs of the fish and wildlife recovery programs are determined by comparing purchased power expenses associated with FCRPS operations before any restrictions were placed on river operations with FCRPS operations for fish mitigation. The Risk Analysis and Mitigation Study uses as a baseline the generation that could have been achieved without the current FRCPS operations for fish mitigation. The critical period Firm Energy Load Carrying Capability (FELCC), before changes for fish and wildlife operations, is used as the base firm energy load for this forecast. The cost of the increased purchases is estimated using RiskMod and the Market Price Forecast and is documented in WP-10-FS-BPA-05A, Summary Table 4.6.1, line 15.

A portion of the increased purchased power expenses (22.3 percent) is included in the section 4(h)(10)(C) credit. See Documentation, WP-10-FS-BPA-05A, Table 4.5. The FCRPS is a multi-purpose river system used for a number of purposes in addition to power production. The 22.3 percent of the increased purchased power expenses represents the non-power portion of the total FCRPS costs. BPA incurs or pays the entire additional power costs and is reimbursed by Treasury for the non-power share of those costs. The total section 4(h)(10)(C) credit is forecast to be $97 million for FY 2010 and $102 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2, line 15. The section 4(h)(10)(C) credit calculations are shown in the Documentation, WP-10-FS-BPA-05A, Table 4.5. The Treasury credit for the Colville Settlement in FY 2010 and FY 2011 is set by legislation at $4.6 million per year [Public Law No. 103-436; 108 Stat. 4577, as amended].

4.4.5 Revenue from the Sale of Generation Inputs and Other Services

Revenue from generation inputs sold to Transmission Services includes Regulating Reserve, Wind Balancing Reserve, and Operating Reserves. Revenue from generation inputs for other services sold by Transmission Services that contain a generation component includes Synchronous Condensing, Generation Dropping, and Imbalance Energy. Other inter-business line revenues include Redispatch, Segmentation of COE and Reclamation network and delivery facilities costs, and station service. All these generation inputs are discussed in the Generation Inputs Study, WP-10-FS-BPA-08.

In FY 2009, revenue from generation inputs and other services is expected to total $81 million, which includes $3 million in revenue received from sales of reserve services. Revenue from the sale of generation inputs at current rates is expected to be $102 million for FY 2010 and $102 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 12. For proposed rates, revenue from the sale of generation inputs is expected to be $90 million for

FY 2010 and $103 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2, line 12. There is no explicit forecast of reserve services for FY 2010 and FY 2011. Starting in FY 2010, revenue from the sale of reserve services is incorporated with net secondary revenue. Generation Inputs Study, WP-10-FS-BPA-08, section 1. The revenue forecast at current rates from the sale of generation inputs for Wind Balancing Service is $15 million for FY 2009, $55 million for FY 2010, and $55 million for FY 2011. For proposed rates, the revenue forecast from the sale of generation inputs for Wind Balancing Service is $39 million for FY 2010 and $56 million for FY 2011. See Generation Inputs Study, WP-10-FS-BPA-08, section 1, Table 1.1 and Documentation, WP-10-FS-BPA-05A, Tables 4.6.1 and 4.6.2.

4.4.6 Slice True-Up

The Slice True-Up Adjustment Charge forecast for FY 2010 is -$5.3 million, which represents an expected credit to Slice customers. Section 2.15.6 and Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 13. The forecast for FY 2011 is $10.9 million, which represents an expected charge to Slice customers. Section 2.15.6 and Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 13.

4.4.7 Energy Efficiency

BPA projects revenues of $20.5 million per year for FY 2010 through FY 2011 from reimbursement for energy efficiency installations. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 18. Energy efficiency revenues are documented in the budget estimates prepared in FY 2009. Documentation, WP-10-FS-BPA-05A, Table 4.9.

4.4.8 Direct Service Industrial Customers (DSIs)

BPA projects revenues of $123 million per year for FY 2010 and FY 2011 from sales to Direct Service Industrial Customers (DSIs) at the current IP rates. See Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 10.

4.5 Power Purchase Expense Forecast

4.5.1 System Augmentation Purchase Expense

As explained in section 4.3.3, 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 486 aMW in FY 2010 and 688 aMW in FY 2011 of system augmentation to meet firm loads. Load and Resources Study, WP-10-FS-BPA-01, Table 2.2. Forecast costs of this system augmentation are $181 million in FY 2010 and $273 million in FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 26.

BPA has contracted with certain Slice customers to purchase ERE of 10 aMW in FY 2010 and 8 aMW in FY 2011. Loads and Resources Study, WP-10-FS-BPA-01. section 2.3.4; Documentation, WP-10-FS-BPA-05A, Table 4.8.3. The ERE amounts are deducted from the aggregate augmentation amounts to determine the augmentation amount used in this Study. The expense for the remaining augmentation amounts, 476 aMW in FY 2010 and 680 aMW in FY 2011, is based on projected prices using the AURORA$^{xmp®}$ model assuming critical water conditions. Risk Analysis and Mitigation Study Documentation, WP-10-FS-BPA-04A, section 1.4. These prices, which are computed as monthly weighted average prices, and the corresponding cost of these augmentation purchases are documented in WP-10-FS-BPA-05A, Table 4.8.3, and can also be found in Summary Table 4.6.1, line 26.

4.5.2 Balancing Power Purchases

Balancing power purchases are calculated by RiskMod, which finds any monthly HLH and LLH energy deficits under each of the 70 water years and applies the corresponding market prices for each water condition. As stated in the Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, section 2.4.11, RiskMod also accounts for winter hedging purchases that BPA has made. BPA made these purchases to cover increasing amounts of 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. The winter hedging purchase amounts and expenses are listed in WP-10-FS-BPA-05A, Table 4.8.3.

The results of the 70 water year run of RiskMod and the resulting balancing purchases are forecast to total $85 million for FY 2010 and $71 million for FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.8.2.

4.6 FY 2010 and FY 2011 Revenue

Revenues using current rates for FY 2010 and FY 2011 are forecast to total $2,778 million for FY 2010 and $2,875 million for FY 2011, excluding bookouts. Documentation, WP-10-FS-BPA-05A, Table 4.6.1. Revenue from firm power sales to public utilities and Federal customers at PF-07R and FPS-07R at current rates is forecast to total $1,720 million in FY 2010 and $1,753 million in FY 2011. *Id.*, Table 4.6.1, lines 5 and 7. Revenue from firm power sales to public utilities and Federal customers at proposed rates is projected to total $1,831 million in FY 2010 and $1,850 million in FY 2011. *Id.*, Table 4.6.2, lines 5 and 7. These amounts exclude the return of Lookback Amounts.

Total revenue under proposed rates is projected to be $2,880 million in FY 2010 and $2,971 million in FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2.

Long-term surplus contract revenues, including sales at PPL-90, WNP-3 Exchange rate, COE and Reclamation reserve energy and Irrigation Pumping Power rates, and other contracts that are determined by prior contractual arrangements, at current rates are projected at current rates to total $86 million in FY 2010 and $78 million in FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.1, line 11. Total long-term surplus contract revenues at proposed rates are projected to be $97 million in FY 2010 and $88 million in FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2, line 11.

Revenues from the sale of generation inputs at proposed rates are projected to be $90 million in FY 2010 and $103 million in FY 2011. *Id.,* line 12.

Revenue from section 4(h)(10)(C) credits is projected to be $102 million in FY 2010 and $102 million in FY 2011 at proposed rates. Documentation, WP-10-FS-BPA-05A, Table 4.5, and Table 4.6.1, line 15. Revenue credited to BPA associated with the Colville Settlement is $4.6 million for both FY 2010 and FY 2011.

DSI revenues for BPA are projected to be $122 million per year for FY 2010 and FY 2011 from sales to DSIs at the proposed IP rates. See Documentation, WP-10-FS-BPA-05A, Table 4.6.2, line 10.

Miscellaneous revenues from the Energy Service activities, Renewable Energy Certificates, Green Energy Premiums, and other sources at proposed rates are projected to total $31 million in

FY 2010 and $31 million in FY 2011. Documentation, WP-10-FS-BPA-05A, Table 4.6.2, lines 14, 18, 19, and 20.

5. RATE SCHEDULE DESCRIPTIONS

The final wholesale power rates and GRSPs described in this section are presented in their entirety in the Administrator's Record of Decision, WP-10-A-BPA-02-AP02.

Each rate schedule describes the customers for whom the rate schedule is available, the date the rate schedule is effective, the proposed rates for the products offered under the schedule, the associated billing factors, and references to sections of the GRSPs that apply to that rate schedule. The rate schedules also contain appropriate transmission purchasing policies and charges for power customers. The transfer services rates include the GTA-10, GTA Delivery Charge and Transfer Service Operating Reserve Charge, described in section 2.14.

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, describe the rate schedules, and define other applicable terms. Appendix A to the rate schedule and GRSP document contains the Slice Rate Methodology. Appendix B contains the Customer Lookback Credit for the Residential Exchange Program.

5.1 Priority Firm Power Rate, PF-10

The proposed PF-10 rate schedule replaces the PF-09 rate schedule and is applicable for the rate period, FY 2010-2011. The PF-10 rate schedule is available for the purchase of power by eligible consumer-owned utilities, Federal agencies, and utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act. PF power must be used to meet the purchasers' firm loads within the Pacific Northwest.

The PF-10 rate schedule includes two sections, one applicable to purchasers under the 2002 Subscription contracts (PF Preference rate) and the other applicable for eligible customers that have signed Residential Purchase and Sale Agreements (PF Exchange rate).

The PF Preference rate is available to meet the general requirements of consumer-owned utilities and Federal agencies. At BPA's discretion, and subject to specified limitations, BPA also may make available the Flexible PF Rate Option, which includes rates and billing factors as mutually agreed upon by BPA and the Purchaser. For customers interested in deferring a portion of the rate increase from FY 2010 to FY 2011, an option is available that determines an alternative payment plan that creates an equal percentage increases in the rates applicable in FY 2010 to the rates applicable in FY 2011. The PF-10 Demand rate is monthly differentiated. The PF-10 Preference Energy rates are monthly and diurnally differentiated.

The PF Exchange rate is a single annual Energy rate, and is subject to a 7(b)(3) Supplemental Rate Charge established specifically for each respective utility, as described in section 2.8.3.

Most purchases under the PF-10 rate schedule are subject to certain provisions of the GRSPs, including, among others, the Conservation Rate Credit, Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause, NFB Mechanisms, Targeted Adjustment Charge, Low Density Discount, and Unauthorized Increase Charge. Customers that choose to purchase the PF Partial Service Complex Product can be subject to the Excess Factoring Charge. Purchases under the PF-10 rate schedule are subject to the BPA billing process.

5.2 New Resource Firm Power Rate (NR-10)

The NR-10 rate schedule is available for purchase of power by investor-owned utilities under net requirements contracts for resale to consumers and to consumer-owned utilities for new large single loads.

NR-10 rates are established for Demand, Energy, and Load Variance. At BPA's discretion, and subject to specified limitations, BPA also may make available the Flexible NR Rate Option, which includes rates and billing factors as mutually agreed to by BPA and the purchaser, as limited by the GRSPs. The NR-10 rate includes a monthly differentiated Demand rate and monthly and diurnally differentiated Energy rates. The Energy rate includes a 7(b)(3) Supplemental Rate Charge. Purchases under the NR-10 rate schedule are subject to certain provisions of the GRSPs, including the CRAC, the NFB Mechanisms, the DDC, the CRC, the LDD, the UAI Charge, and for some products, the Excess Factoring Charge. Purchases under the NR-10 rate schedule are subject to the BPA billing process.

5.3 Industrial Firm Power Rate (IP-10)

The IP-10 rate schedule is available to BPA's direct-service industrial customers for firm take-or-pay block power to be used in their Pacific Northwest industrial operations.

The IP-10 rate schedule includes a monthly differentiated Demand rate and monthly and diurnally differentiated Energy rates. Energy rates include a 7(b)(3) Supplemental Rate Charge and a Value of Reserves credit. Purchases under the IP-10 rate schedule are subject to provisions of the GRSPs, as listed in the rate schedule, including, but not limited to, the DSI Reserves Adjustment, the CRAC, the NFB Mechanisms, the DDC, and the UAI Charge.

5.4 Firm Power Products and Services Rate (FPS-10)

The FPS-10 rate schedule is available for purchase of Firm Power, Capacity, Capacity without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services, and Reassignment or Remarketing of Surplus Transmission Capacity inside and outside the Pacific Northwest. The FPS-10 contains a Flexible rate. The Flexible rate is a negotiable, market-based rate. The Flexible rate may have a Demand component, an Energy component, or both, and is subject to a 7(b)(3) Supplemental Rate Charge. Unbundled products also are available under the FPS-10 rate schedule at flexible rates as mutually agreed by the contracting parties. Applicable transmission rates will apply, to the extent required, to purchases of firm power under the FPS-10 rate. Purchases under the FPS-10 rate schedule also are subject to the BPA billing process.

6. AVERAGE SYSTEM COST FOR THE RESIDENTIAL EXCHANGE PROGRAM

6.1 Overview of Average System Cost and Residential Exchange Program

This section describes BPA's process for estimating the Average System Cost (ASC) of resources used to produce electricity sold by utilities participating in the Residential Exchange Program (REP) for FY 2010-2011.

Under the REP, BPA offers to purchase power from each participating utility at that utility's ASC. BPA then offers, in exchange, to sell an equivalent amount of electric power to the utility at BPA's PF Exchange rate. The amount of power purchased and sold is equal to the qualifying residential and small farm load of each utility participating in the REP. The monetary benefits of this "exchange" must be passed on to the residential and small farm customers of the utility.

Utility ASCs are not determined in BPA rate proceedings. Instead, ASCs are determined in a separate administrative process (the ASC Review Process) that BPA conducts pursuant to the procedural rules of the 2008 ASC Methodology (ASCM), which were granted interim approval by the Commission on October 10, 2008. *See* 18 C.F.R. 301.4, *et seq.*

Utility ASCs, once established in the ASC Review Process, are one component used in the WP-10 rate development process to forecast the REP costs that must be collected in rates for the rate period.

For clarity and context in this rate proposal, certain components of the ASC determination are described for the rate period, FY 2010-2011. Background information, publications, procedures and review schedules, and BPA's published reports are located at http://www.bpa.gov/corporate/finance/ascm/.

6.2 ASC Determination

A utility interested in participating in the REP is required to submit cost and load data to BPA for an ASC determination through the formal ASC Review Process. The quotient resulting from dividing a utility's ASC Contract System Cost by the utility's ASC Contract System Load is the utility's ASC.

The ASC Contract System Cost is the sum of the utility's allowable production- and transmission-related costs. The ASC Contract System Load is the sum of the total retail load of a utility, as measured at the meter, plus distribution losses, less any new large single loads, if applicable. BPA establishes a utility's Contract System Cost and Contract System Load pursuant to the 2008 ASCM in consultation with regional parties. A summary of the total retail loads is shown in the Loads and Resources Study Documentation, WP-10-FS-BPA-01A, Table 2.2.7. Distribution losses are calculated using the distribution loss factor contained in the utilities' ASC submittals to BPA. In addition, as part of their ASC submittals, the utilities include any NLSLs they are currently serving or are projected to serve during the ASC Exchange Period (FY 2010-2011). No utilities identified any new NLSLs for this rate period; therefore, the NLSLs are assumed to remain constant from prior years through FY 2010-2011. In addition, the kWh consumption of NLSLs is assumed to remain constant through FY 2010-2011.

As described more fully below, BPA updated the ASCs used to determine the WP-10 rates. The revised ASCs incorporate updated data from the participating utilities' Contract System Cost and Contract System Load forecasts, resource costs to serve NLSLs, distribution loss factors, and resulting ASCs, with the final ASC determinations made in the ASC Review Process for FY 2010-2011.

6.3 Average System Costs for FY 2010-2011

A utility's ASC is established for the entire rate period prior to BPA's final rate determination in its rate proceedings. ASCs are determined through an ASC Review Process that normally begins on or about June 1st prior to the start of the 7(i) ratesetting process. Once the ASC Review Process is complete and the utility's ASC is established, BPA publishes a Final ASC Report. The data found in this Final ASC Report are used to calculate the utility's REP benefits for the term of the ASC Exchange Period, which coincides with BPA's rate period. The ASCs are also available to be used as an input in BPA's rate cases to estimate REP costs for purposes of setting rates.

The WP-10 rate proceeding presented a unique transition-year problem. The 2008 ASC Methodology was filed with the Commission on July 7, 2008, and approved on an interim basis on October 10, 2008. Because of the timing of BPA's filing of the ASC Methodology, it was not possible for BPA to commence an ASC Review Process by June 1, 2008. To address this transition-year issue, BPA notified all parties intending to participate in the REP for FY 2010-2011 that they must file proposed ASCs with BPA no later than October 15, 2008. Eight utilities responded to this request and filed ASCs with BPA, and BPA simultaneously completed the review and evaluation of these ASC filings in eight separate ASC Review Processes. The following six IOUs and two COUs filed ASCs with BPA: Avista Utilities, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Franklin County PUD, and Snohomish County PUD.

The ASC Review Processes were completed in conjunction with BPA's final WP-10 rate determinations. Excerpts of each utility's Final ASC Reports for FY 2010-2011 are incorporated into the record of the WP-10 proceeding and may be viewed in the WPRDS documentation, WP-10-FS-BPA-05A, section 5. The complete FY2010-2011 Final ASC Report for each utility may be viewed at http://www.bpa.gov/corporate/finance/ascm/fy10-asc-final-reports.cfm.

6.4 Changes to As-Filed ASCs for FY 2010-2011

As stated above, the determination of a utility's ASC is completed in a separate process outside the WP-10 rate proceeding.

For the WP-10 rates, the rate period ASCs, based on the Administrator's final determinations following the ASC Review Processes, are used in the rate development process. During the Review Processes, BPA made certain changes that affected all utilities. First, the forecasts of inflation, natural gas prices, and market prices were updated to be consistent with the forecast used in the WP-10 Final Proposal. Second, the utilities' ASC filings were corrected, as necessary, for errors found during the formal Review Processes of the utilities' ASC submittals. Finally, additional changes were made due to the Administrator's determination of ASC issues. For specific details on all ASC related issues, including changes and/or corrections to the ASC filing, see the specific utility's Final ASC Report at http://www.bpa.gov/corporate/finance/ascm/fy10-asc-final-reports.cfm. Excerpts of each report are located in the WPRDS Documentation, WP-10-FS-BPA-05A, chapter 5.

Table 6.1 below lists the FY 2010-2011 BPA-determined rate period ASCs. The ASCs shown are annual weighted averages for each utility. The actual ASC for each utility may change if the utility adds a new resource or retires an existing resource. The actual ASCs and additional ASC information, including the 2008 ASC Methodology, is located at BPA's ASCM web site: http://www.bpa.gov/corporate/finance/ascm/.

Table 6.1
FY 2010-2011 Exchange Period ASCs ($/MWh)

	A	**B**
Utility	**FY 2010**	**FY 2011**
Avista	46.98	47.80
Franklin County PUD	49.28	49.28
Idaho Power	35.65	35.65
Northwestern	57.57	57.57
PacifiCorp	56.48	56.60
Portland General	55.57	58.21
Puget Sound Energy	56.98	61.63
Snohomish County PUD	46.33	45.91

6.5 ASC Forecast for Remaining Years of the 7(b)(2) Rate Test Period (FY 2012-2015)

The 7(b)(2) rate test requires a forecast of utility ASCs for the rate period (FY 2010-2011) and the following four years (FY 2012-2015). The methodology used to forecast utility ASCs for the FY 2012-2015 period is discussed in the Section 7(b)(2) Rate Test Study, WP-10-FS-BPA-06, section 3.