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

2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12)

ADMINISTRATOR'S FINAL RECORD OF DECISION

Appendix B: Power Rate Schedules

July 2011

BP-12-A-02B

BONNEVILLE
POWER ADMINISTRATION

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BONNEVILLE POWER ADMINISTRATION

POWER RATE SCHEDULES

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COMMONLY USED ACRONYMS AND SHORT FORMS

AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
Commission	Federal Energy Regulatory Commission
Corps or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium

GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OY	operating year (August through July)

PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase

ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

POWER RATE SCHEDULES

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SCHEDULE PF-12
PRIORITY FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of Firm Requirements Power pursuant to section 5(b) of the Northwest Power Act. Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service.

Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Residential Exchange Program Power pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the PF-10 rate schedule, which went into effect October 1, 2009. Sales under the PF-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer consist of two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to Customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice and Slice Customer rates are specified in the following table:

	Customer Charge ***Rate per percentage point of billing determinant***		
	Composite	***Non-Slice***	***Slice***
Customer Rate	$1,952,169	($388,748)	$0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice and Slice Customer billing determinants are specified in the following table:

	Customer Charge ***Billing determinant for each rate***		
	Composite	***Non-Slice***	***Slice***
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percent

For each Customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\begin{array}{c}\textit{Minimum of the Customer's:}\\ \textit{a) RHWM, or}\\ \textit{b) Forecast Net Requirement for each Fiscal Year}\end{array}}{\textit{Sum of all Customers' RHWMs}} \times 100$$

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All Customer TOCAs will be posted on the BPA Web site. A Customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.T.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice Customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percent

A Customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.T.

2.1.2 Demand Charge

The Demand Charge is applicable to Customers that purchase the following products: Load Following and Block with Shaping.

2.1.2.1 Demand Rate

Month	***Rate in $/kW***
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = The Tier 1 Customer System Peak is the Customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts.

aHLH = Average of the Customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the Customer's CHWM Contract, Exhibit B, section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the Customer's CHWM Contract, Exhibit A, section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

If a Customer purchases Secondary Crediting Service, the Demand billing determinant may be adjusted pursuant to GRSP II.P.2.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to Customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period, the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

Month	***Rate in mills/kWh Diurnal Period:***	
	HLH	***LLH***
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

Customer's Actual Monthly/Diurnal Tier 1 Load,
in kilowatthours
Minus
Customer's System Shaped Load for the relevant diurnal period,
in kilowatthours

If a Customer purchases Secondary Crediting Service (SCS), the Load Shaping billing determinant may be adjusted pursuant to GRSP II.P.2.

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The Customer's System Shaped Load for each diurnal period equals:

$$RT1SC \times TOCA$$

Where:

RT1SC = RHWM Tier 1 System Capability for the relevant diurnal period, in kilowatthours. The RT1SC for each diurnal period of the Rate Period is specified in GRSP II.Q.

TOCA = The effective TOCA for a Load Following or Block Customer, or the effective Non-Slice TOCA for a Slice/Block Customer, expressed as a percent. The TOCA used in this System Shaped Load calculation shall reflect a Customer's Adjusted TOCA pursuant to GRSP II.T.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a Joint Operating Entity (JOE), the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.2 Tier 2 Charges

2.2.1 Short-Term Charge

The Short-Term Charge is applicable to Customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.1.1 Short-Term Rate

FY	***Rate in mills/kWh***
2012	46.48
2013	48.69

2.2.1.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.2 Load Growth Charge

The Load Growth Charge is applicable to Customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.2.1 Load Growth Rate

FY	***Rate in mills/kWh***
2012	N/A
2013	48.63

N/A = Not Applicable

2.2.2.2 Load Growth Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3 Priority Firm Melded Rate

The PF Melded Rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Melded Rate is not available to loads that are considered unanticipated loads as defined in Unanticipated Load Service, GRSP II.U.1.

3.1 Energy Charge

3.1.1 Energy Rate

Month	*Rate in mills/kWh Diurnal Period:*	
	HLH	***LLH***
October	31.04	24.38
November	31.55	24.58
December	34.28	26.57
January	33.21	24.88
February	34.11	26.35
March	32.75	25.51
April	30.71	23.59
May	28.24	17.58
June	29.15	16.2
July	35.25	23.09
August	37.53	25.33
September	36.63	26.77

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the Customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

Month	***Rate in $/kW***
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the Customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4 Unanticipated Load Rate

The Unanticipated Load Rate is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in Unanticipated Load Service, GRSP II.U.1.

5 Resource Support Services Rates

Resource Support Services rates are applicable to Customers that elect to take Diurnal Flattening Service or Secondary Crediting Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to Customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contract.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges, specified in GRSP II.P.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources, other than small non-dispatchable resources, are subject to the Resource Shaping Charge and Adjustment, specified in GRSP II.P.1.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge, specified in GRSP II.P.2.

6 Priority Firm Exchange Rate

The PF Exchange Rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange Rate plus a utility-specific 7(b)(3) Surcharge. For consumer-owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange Rate plus a utility-specific 7(b)(3) Surcharge.

	Rates in mills/kWh		
Investor-Owned Utilities	***Base PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Avista	43.06	11.37	54.429
Idaho Power	43.06	3.23	46.282
NorthWestern	43.06	7.75	50.809
PacifiCorp	43.06	13.80	56.858
Portland General	43.06	18.79	61.842
Puget Sound Energy	43.06	16.78	59.833
Consumer-Owned Utilities	***Base Tier 1 PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Clark Public Utilities	43.03	10.73	53.76
Snohomish PUD	43.03	2.38	45.41

6.1.1 7(b)(3) Surcharge for Non-Listed Utilities

For eligible Customers not listed in section 6.1, the applicable 7(b)(3) Surcharge will equal the Customer's Average System Cost minus the applicable Base PF Exchange rate. The Customer's Average System Cost will be determined pursuant to BPA's 2008 Average System Cost Methodology.

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the Customer's Residential Load specified in GRSP II.N.

7 Adjustments, Charges and Special Rate Provisions

Adjustments, charges and special rate provisions are applicable to PF rates as shown in the following table.

		Applicable to:			
		Firm Requirements			
GRSP II.	***Adjustments, Charges and Special Rate Provisions***	***Load Following***	***Block only and Block Portion of Slice/Block***	***Slice Portion of Slice/Block***	***REP***
A	Conservation Surcharge	*X*	*X*	*X*	
B	Cost Contributions	*X*	*X*		
C	Cost Recovery Adjustment Clause (CRAC)	*X*	*X*		
D	Dividend Distribution Clause (DDC)	*X*	*X*		
G	Flexible Priority Firm Power (PF) Rate Option	*X*	*X*		
H	Irrigation Rate Discount	*X*	*X*	*X*	
I	Load Shaping Charge Adjustment	*X*	*X*		
J	Low Density Discount (LDD)	*X*	*X*	*X*	
K	NFB Mechanisms	*X*	*X*		
L	Priority Firm Power (PF) Shaping Option	*X*	*X*		
N	Residential Load				*X*
O	7(b)(3) Surcharge Adjustment				*X*
P	Resource Support Services and Transmission Scheduling Service	*X*	*X*	*X*	
Q	RHWM Tier 1 System Capability (RT1SC)	*X*	*X*		
R	Slice True-Up Adjustment			*X*	
S	Tier 2 Rate TCMS Adjustment	*X*			
T	TOCA Adjustment	*X*	*X*		
U	Unanticipated Load Service	*X*	*X*		
V	Unauthorized Increase (UAI) Charge	*X*	*X*	*X*	*X*

SCHEDULE NR-12
NEW RESOURCE FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service. New Resources Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the NR-10 rate schedule. Sales under the NR-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

Month	***Rate in mills/kWh Diurnal Period:***	
	HLH	***LLH***
October	71.70	65.04
November	72.21	65.24
December	74.94	67.23
January	73.87	65.54
February	74.77	67.01
March	73.41	66.17
April	71.37	64.25
May	68.90	58.24
June	69.81	56.86
July	75.91	63.75
August	78.19	65.99
September	77.29	67.43

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 7.72 mills/kWh.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

Month	***Rate in $/kW***
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3 Unanticipated Load Rate

The Unanticipated Load Rate is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.U.3.

4 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Conservation Surcharge	A
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Dividend Distribution Clause (DDC)	D
Flexible New Resource Firm Power (NR) Rate Option	F
Low Density Discount (LDD)	J
NFB Mechanisms	K
Unanticipated Load Service	U
Unauthorized Increase (UAI) Charge	V

SCHEDULE IP-12
INDUSTRIAL FIRM POWER RATE

1 Availability

This schedule is available to BPA's direct service industrial Customers (DSIs), as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power (IP) is available under Northwest Power Act section 5(d) contracts to DSIs for direct consumption.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the IP-10 rate schedule. Sales under the IP-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-12 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2 Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

	Rate in mills/kWh *Diurnal Period:*	
Month	***HLH***	***LLH***
October	38.51	31.85
November	39.02	32.05
December	41.75	34.04
January	40.68	32.35
February	41.58	33.82
March	40.22	32.98
April	38.18	31.06
May	35.71	25.05
June	36.62	23.67
July	42.72	30.56
August	45.00	32.80
September	44.10	34.24

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 7.72 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.94 mill/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.2 Energy Billing Determinant

The energy billing is the Energy Entitlement that is specified in the Customer's contract.

2.2 Demand Charge

2.2.1 Demand Rate

Month	*Rate in $/kW*
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.2.2 Demand Billing Determinant

The billing determinant is the Customer's maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the Customer's monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

Month	*Industrial Demand Adjuster (kW)*
October	3,495
November	2,811
December	1,982
January	1,741
February	1,905
March	2,730
April	1,358
May	1,916
June	1,304
July	1,354
August	1,542
September	1,249

In the event Port Townsend's historical Contract Demand (20.5 MW) is reduced in part or in all by BPA due to the transfer of service to a BPA preference customer the Industrial Demand Adjuster values in the above table will be reduced proportionally.

3 Adjustments, Charges and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

Adjustments, Charges, and Special Rate Provisions	*GRSP II.*
Conservation Surcharge	A
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Dividend Distribution Clause (DDC)	D
DSI Reserves Adjustment	E
NFB Mechanisms	K
Unauthorized Increase (UAI) Charge	V

FPS-12
FIRM POWER PRODUCTS AND SERVICES RATE

1 Availability

This rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, and Unanticipated Load Service for use inside and outside the Pacific Northwest.

Sales under this rate schedule are discretionary. BPA is not obligated to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2011, this rate schedule supersedes the FPS-10 rate schedule. Sales under the FPS-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Firm Power and Capacity Without Energy

2.1 Flexible Rate

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the Customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Customer.

2.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

3 Supplemental Control Area Services

3.1 Rates and Billing Determinants

The charge for Supplemental Control Area Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Supplemental Control Area Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

3.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

4 Shaping Services

4.1 Rates and Billing Determinants

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

4.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***GRSP II.***
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

5 Reservations and Rights to Change Services

5.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reservation and Rights to Change Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

5.2 Adjustments, Charges, and Special Rate Provisions

There are no additional adjustments, charges, or special rate provisions for the Reservation and Rights to Change Services.

6 Reassignment or Remarketing of Surplus Transmission Capacity

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

6.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the Customer.

6.2 Adjustments, Charges, and Special Rate Provisions

There are no additional adjustments, charges, or special rate provisions for the Reassignment or Remarketing of Surplus Transmission Capacity.

7 Services for Non-Federal Resources

7.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.P.4, Resource Support Services and Transmission Scheduling Service.

7.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.P.3.

8 Unanticipated Load Service

The Unanticipated Load Service is applicable to the sale of firm power to serve unanticipated loads resulting from a request for service under section 9(i) of the Northwest Power Act. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.U.4.

GTA-12
GENERAL TRANSFER AGREEMENT SERVICE RATE

1 Availability

This schedule applies to BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements.

2 GTA Delivery Charge

The GTA Delivery Charge is a BPA Power Services charge for low-voltage delivery service of Federal power provided under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements. The GTA Delivery Charge shall apply to Customers that purchase Federal power that is delivered over non-Federal low-voltage transmission facilities.

1.1 Rate

	Rate in $/kW
All months	1.119

1.2 Billing Determinant

The monthly billing determinant for the GTA Delivery rate shall be the total load on the hour of the Monthly Transmission Peak Load at the low voltage Points of Delivery provided for in GTA and other non-Federal transmission service arrangements.

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the billing determinant shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery, multiplied by 0.79.

Monthly Transmission Peak Load is the peak loading on the Federal transmission system during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area (also known as Balancing Authority Area) and metered flow into BPA's Control Area.

3 Transfer Service Operating Reserve Charge

Power Services Customers served by GTAs or other non-Federal transmission service agreements (hereafter "by transfer") will be subject to the Transfer Service Operating Reserve Charge at such time that Transmission Services implements the WECC proposed reliability standard, BAL-002-WECC-1, regarding operating reserve (hereafter "the 3 and 3 reliability standard"). At such time, the Transfer Service Operating Reserve Charge will apply to power Customers that meet the following criteria: (1) Power Services serves the

Customer by transfer; (2) the power Customer does not pay Transmission Services for operating reserve based on the 3 and 3 reliability standard for the Customer’s load; and (3) Power Services is assessed operating reserve charges by a third-party transmission provider for service to the power Customer’s load.

2.1 Rate

2.1.1 The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-12 Operating Reserve – Spinning Reserve Service rate.

2.1.2 The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-12 Operating Reserve – Supplemental Reserve Service rate.

2.2 Billing Determinant

2.2.1 The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the ACS-12 Operating Reserve – Spinning Reserve Service except that the load used to calculate the billing determinant for Power Services charges will be the load of the Customer served by transfer.

2.2.2 The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the ACS-12 Operating Reserve – Supplemental Reserve Service except that the load used to calculate the billing determinant for Power Services charges will be the load of the Customer served by transfer.

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS (GRSPs)

SECTION I. ADOPTION OF REVISED POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

The Power Rate Schedules and these General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (Commission). BPA will request that the Commission make these rates and GRSPs effective on October 1, 2011. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power Rate Schedules and GRSPs associated with the schedules supersede BPA's 2010 Power Rate Schedules, which became effective October 1, 2009, to the extent stated in the Availability Section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: The Bonneville Project Act, the Regional Preference Act (P.L. 88-552), the Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

The rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365, shall be applied each day to any unpaid balance. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The Customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services "Direct Assignment Facilities Guidelines," as amended or superseded (Transmission Services Guidelines), currently posted at:
http://transmission.bpa.gov/ts_business_practices/

In determining whether to directly assign to a Transfer Customer costs incurred by BPA in providing transfer service to the customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference Customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most pro forma Open-Access Transmission Tariffs (OATT), are:

> Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer….

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the customer.

Supplemental Guideline Regarding Voltages below 34.5 kV

For new facilities or new service over existing third-party transmission provider facilities at voltages below 34.5 kV that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses to the point where the voltage is at or above 34.5 kV, such that BPA is not responsible for losses across such facilities. Loss calculations should be similar whether the customer or the transmission provider owns the delivery facilities. *Note*: The cut-off voltage of 34.5 kV is used in the Transmission Services Guidelines. If this voltage level is changed in the Transmission Services Guidelines, these Supplemental Guidelines will be deemed modified.

Supplemental Guidelines Regarding Replacement with Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting customer. Alternatively, BPA and the customer may agree to full direct assignment in lieu of payment of the GTA Delivery Charge. Similarly, when a parallel transformer is added, BPA and the customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

If a customer receives new Transfer Service over new or pre-existing facilities below 34.5 kV offered by the transfer provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the GTA Delivery Charge. BPA will not assess the GTA Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation

On any new arrangement for delivery below 34.5 kV (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider

A customer may, in lieu of paying the GTA Delivery Charge, choose to contract directly with the third-party transmission provider for delivery below 34.5 kV for an existing POD, but must then do so for all similar PODs with that transmission provider. The customer must take delivery from BPA at or above 34.5 kV for these PODs such that the customer is responsible for costs of and losses through the delivering facilities. A customer contracting with the third party for a new POD does not create a requirement that the customer contract with the third party for its pre-existing low voltage PODs.

F. Metering Usage Data Estimation Provision

Pursuant to section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering Web site.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge, if implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the Customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-12 (including Slice purchasers), IP-12, and NR-12 rate schedules.

B. Cost Contributions

Pursuant to section 7(j) of the Northwest Power Act, BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is:

Table A
Resource Cost Contribution

Rate Schedule	***Federal Base System***	***Exchange Resources***	***New Resources***
PF	44.77%	55.23%	0%
IP	0%	67.89%	32.11%
NR	0%	67.89%	32.11%
FPS	0%	67.89%	32.11%

2. The cost of resources acquired to meet load growth within the region is estimated to be 47.93 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 42.52 mills/kWh.

C. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to certain rates that can apply to rates during FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Accumulated Net Revenue (ANR) for the fiscal year preceding the applicable year. If the forecast ANR is less than the CRAC Threshold for that applicable year by at least $5 million, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year.

(a) Calculating the CRAC Amount

The CRAC Amount is based on the Underrun, which is equal to the CRAC Threshold minus forecast ANR. There are four possibilities:

(1) If the Underrun is less $5 million there is no CRAC.

(2) If the Underrun is greater than or equal to $5 million and less than or equal to $100 million, the CRAC Amount is equal to the Underrun.

(3) If the Underrun is greater than $100 million and less than $500 million, the CRAC Amount is equal to $100 million plus one-half of the difference between $100 million and the Underrun.

(4) If the Underrun is greater than or equal to $500 million, the CRAC Amount is equal to $300 million.

NOTE: In cases 3 and 4 above, if an NFB Adjustment increases the CRAC Cap from $300 million to a higher number, the terms will be adjusted. In cases 3 and 4, the "$500 million" figure will be replaced by $500 million plus twice the difference between the new Cap and $300 million. In case 4, the "$300 million" figure will be replaced by the new Cap.

The CRAC Cap and thresholds are shown in Table B.

Table B: CRAC Annual Thresholds and Caps
(dollars in millions)

ANR Calculated near End of Fiscal Year	*CRAC Applied to Fiscal Year*	*CRAC Threshold Measured in ANR*	*Approx. Threshold as Measured in Power Services Reserves for Risk*	*Maximum CRAC Recovery Amount (Cap)**
2011	2012	($187.6)	$0	$300
2012	2013	($143.4)	$0	$300

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered).

Where:

CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate during the year of application.

CRAC Threshold is the "trigger point" for invoking a rate increase under the CRAC.

ANR is Accumulated Net Revenue for the generation function, as accumulated since the end of FY 2010. A forecast of ANR is used to determine whether the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of ANR for use in determining the CRAC that will apply to FY 2012 rates will be the forecast of PS Net Revenue for FY 2011. The forecast of ANR for use in determining the CRAC that will apply to FY 2013 rates will be the sum of the PS Net Revenue for FY 2011 plus the forecast of PS Net Revenue for FY 2012.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum CRAC Recovery Amount (Cap) is the maximum annual amount that is allowed to be recovered through the CRAC.

(b) Calculating the PF/IP/NR CRAC Amount and the ACS CRAC Amount

The PF/IP/NR CRAC Amount is 96.4% times the CRAC Amount.

The ACS CRAC Amount is 3.6% times the CRAC Amount.

(c) Converting the PF/IP/NR CRAC Amount to the PF/IP/NR CRAC Surcharge

Once the PF/IP/NR CRAC Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to each of the monthly/diurnal PF Melded, IP, and NR energy rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer Rate.

The PF/IP/NR CRAC Surcharge rate is calculated by dividing the PF/IP/NR CRAC Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR CRAC Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

(1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR CRAC Surcharge rate. The product of this calculation is the annual dollar amount to be collected through the Non-Slice TOCA billing determinant.

(2) The annual dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) CRAC Charges for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing additional charges calculated by multiplying the PF/IP/NR CRAC Surcharge by the applicable kilowatthours of service.

For service under Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS CRAC Amount to Charges on Customers' Bills

Once the ACS CRAC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H. for details of how those Transmission rates subject to the CRAC will be modified.

(f) Other Rate Adjustments

The Surcharge rate, calculated pursuant to section 1(c), will be subtracted from the Load Shaping Charge True-up rate to create the CRAC-Adjusted Load Shaping True-up rate. See GRSP II.I.

The Surcharge rate, calculated pursuant to section 1(c), will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.R.

The Surcharge rate, calculated pursuant to section 1(c), will also be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.M.

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ANR forecast for the end of that year; if that amount is below the CRAC Threshold, a CRAC rate adjustment will be made for the next fiscal year.

3. CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, *end-of-year* forecast of ANR attributable to the generation function.

(b) Notification of CRAC Trigger

BPA shall complete a forecast of end-of-year ANR in July of 2011 for use in calculating the CRAC applicable to rates in FY 2012 and in September 2012 for use in calculating the CRAC applicable to rates in FY 2013. If the forecast value of ANR is below the CRAC Threshold applicable to the following year by at least $5 million, then BPA shall notify all Customers and rate case parties by late July 2011 of the amount by which BPA intends to adjust rates for FY 2012 due to the CRAC, and by late September 2012 of the amount by which BPA intends to adjust rates for FY 2013.

Notification will be posted on BPA's Web site and will include the forecast of ANR for the current fiscal year, the audited ANR for FY 2011 in the case of the CRAC applicable to FY 2013 rates, the CRAC Amount, the PF/IP/NR CRAC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the CRAC-adjusted Load Shaping True-up rate, the CRAC-adjusted PF Melded Equivalent Energy Scalar, the ACS CRAC Amount, and details about how the ACS CRAC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ANR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification as described above of CRAC calculations, BPA shall conduct a workshop(s) to explain the ANR calculations, describe the calculation of the CRAC Amount and allocations to various rates, and demonstrate that the CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

The Administrator may exercise discretion and elect to reduce the CRAC rate adjustment provided (1) the resulting TPP for the remainder of the rate period is greater than or equal to BPA's TPP standard (95 percent for the FY 2012-2013 period in the case of the CRAC applicable to FY 2012 rates; 97.5 percent in the case of the CRAC applicable to FY 2013 rates); and (2) the reduced CRAC will recover in the following year the first $100 million of any use by BPA to pay Power bills of the Treasury Facility or reserves attributed to Transmission Services plus one-half of any use of the Treasury Facility or reserves attributed to Transmission Services beyond $100 million, up to a maximum of the CRAC Cap as described above. In the case of the CRAC applicable to the FY 2012 rates, the Administrator may modify the parameters for the CRAC applicable to FY 2013 rates to meet the one-year TPP standard for FY 2013; criterion (2) above must still be met. If the Administrator so elects, the Customers shall be informed during the workshop.

If the CRAC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.K) to the CRAC Cap. If the CRAC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.K) to the CRAC Cap.

D. Dividend Distribution Clause (DDC)

The DDC is a downward adjustment to certain rates that can apply to rates during FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The DDC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will forecast the end-of-year Accumulated Net Revenue (ANR) for the fiscal year preceding the applicable year. If the forecast ANR is greater than the DDC Threshold for that applicable year by at least $5 million, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the DDC Amount

The DDC Amount will be equal to either the forecast ANR less the DDC Threshold or $1,000 million, whichever is smaller.

Table C: DDC Annual Thresholds and Cap
(Dollars in Millions)

ANR Calculated near End of Fiscal Year	*DDC Applied to Fiscal Year*	*DDC Threshold Measured in ANR*	*Approx. Threshold as Measured in Power Services Reserves for Risk*	*Maximum DDC Amount (Cap)*
2011	2012	$562.4	$750	$1,000
2012	2013	$606.6	$750	$1,000

Where:

DDC Amount is the reduction in net revenue that a decrease in rates, due to the DDC, is intended to generate during the year of application.

DDC Threshold is the "trigger point" for invoking a rate decrease under the DDC.

ANR is Accumulated Net Revenue for the generation function, as accumulated since the end of FY 2010. A forecast of ANR is used to determine whether the DDC Threshold has been reached, and if so, the required DDC Amount to be collected. The forecast of ANR for use in determining the DDC that will apply to FY 2012 rates will be the forecast of PS Net Revenue for FY 2011. The forecast of ANR for use in determining the DDC that will apply to FY 2013 rates will be the sum of the PS Net Revenue for FY 2011 plus the forecast of PS Net Revenue for FY 2012.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum DDC Recovery Amount (Cap) is the maximum annual amount that is allowed to be distributed through the DDC.

(b) Calculating the PF/IP/NR DDC Amount and the ACS DDC Amount

The PF/IP/NR DDC Amount is 96.4% times the DDC Amount.

The ACS DDC Amount is 3.6% times the DDC Amount.

(c) Converting the PF/IP/NR DDC Amount to the PF/IP/NR DDC Credit

Once the PF/IP/NR DDC Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DDC Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DDC Credit will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and subtracted from the Non-Slice Customer Rate.

The PF/IP/NR DDC Credit rate is calculated by dividing the PF/IP/NR DDC Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR DDC Credit rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

(1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR DDC Credit rate. The product of this calculation is the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant.

(2) The annual dollar amount to be distributed through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) DDC Credits for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing credits calculated by multiplying the PF/IP/NR DDC Credit by the applicable kilowatthours of service.

For service under the PF Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a credit calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS DDC Amount to Charges on Customers' Bills

Once the ACS DDC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H for details of how those Transmission rates subject to the DDC will be modified.

(f) Other Rate Adjustments

The Credit rate, calculated pursuant to section 1(c), will be added to the Load Shaping True-up Rate to create the DDC-Adjusted Load Shaping True-up Rate. See GRSP II.I.

The Credit rate, calculated pursuant to section 1(c), will be added to the PFp Melded Equivalent Energy Scalar to create the DDC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.R.

The Credit rate, calculated pursuant to section 1(c), will also be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.M.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ANR forecast for the end of that year; if that amount is above the DDC Threshold, a DDC rate adjustment will be made for the next fiscal year.

(a) DDC Notification Process

BPA shall follow these notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, *end-of-year* forecast of ANR attributable to the generation function.

(2) Notification of DDC Trigger

BPA shall complete a forecast of end-of-year ANR in July of 2011 for use in calculating the DDC applicable to rates in FY 2012 and in September 2012 for use in calculating the DDC applicable to rates in FY 2013. If the forecast value of ANR is above the DDC Threshold applicable to the following year by at least $5 million, then BPA shall notify all Customers and rate case parties by late July 2011 of the amount by which BPA intends to adjust rates for FY 2012 due to the DDC, and by late September 2012 of the amount by which BPA intends to adjust rates for FY 2013.

Notification will be posted on BPA's Web site and will include the forecast of ANR for the current fiscal year, the audited ANR for FY 2011 in the case of the DDC applicable to FY 2013 rates, the DDC Amount, the PF/IP/NR DDC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the DDC-adjusted Load Shaping True-up rate, the DDC-adjusted PF Melded Equivalent Energy Scalar, the ACS DDC Amount, and details about how the ACS DDC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ANR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification as described above of DDC calculations, BPA shall conduct a workshop(s) to explain the ANR calculations, describe the calculation of the DDC Amount and allocations to various rates, and demonstrate that the DDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the DDC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final DDC calculations. If the DDC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final DDC calculations.

E. DSI Reserves Adjustment

A DSI Customer's Wholesale Power bill may be adjusted to reflect a DSI Reserves Adjustment. BPA Power Services is not obligated to purchase any DSI Reserve(s) beyond the Minimum DSI Operating Reserve – Supplemental, but is willing to negotiate with any DSI interested in providing additional DSI Reserves. A DSI Reserve is provided through an ability for BPA to interrupt, curtail, or otherwise reduce DSI load when such a right is made available to Power Services in addition to the Minimum DSI Operating Reserve – Supplemental.

This optional DSI Reserves Adjustment is designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the rate based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost effective, the maximum amount Power Services may pay a DSI for DSI Reserve(s) is $6.96 per kW per month.

The availability of DSI Reserve(s) purchased by Power Services must be consistent with North American Electric Reliability Corporation, Western Electricity Coordinating Council, and Northwest Power Pool standards and criteria specific to balancing authority area Operating Reserve requirements, including the two characteristics below:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased; and

2. The interruptible load or increased generation must be accessible prior to a request for reserves from other Northwest Power Pool parties.

In addition to these two required characteristics, the issues identified below will help define when Power Services may pay the maximum value for DSI Reserves:

1. The extent to which Power Services has the discretion when and how to use all reserves and to determine what resources to call on in the event of a system disturbance, or for some other purpose specified in the negotiated arrangement.

2. Whether there are limitations on the number of times or total minutes the reserves may be utilized.

3. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

Even in the event that a DSI is willing to provide reserves meeting all of the criteria established above, the Administrator is not obligated to purchase reserves in any amount beyond the Minimum DSI Operating Reserve – Supplemental.

F. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-12 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

> Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in the sections 2 and 3 of the NR-12 rate schedule been applied to the same sales.
>
> The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2 and 3 of the NR-12 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-12 rate and associated GRSPs, any rights and obligations of BPA and a Customer arising out of the Customer's election to participate in the Flexible NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

G. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-12 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in sections 2, 3, 4, and 5 of the PF-12 rate schedule been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2, 3, 4, and 5 of the PF-12 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-12 rate 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 Rate program by purchasing under the Flexible PF Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

H. Irrigation Rate Discount

1. Discount for Eligible Customers

In May, June, July, August, and September, an eligible Customer shall have the Irrigation Rate Discount of 10.26 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

For a Load Following or Block Customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block Customer, the energy purchased at Tier 1 rates will be equal to the sum of its monthly Block purchase at Tier 1 rates plus its Slice Percentage multiplied by the monthly/diurnal RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a Joint Operating Entity (JOE) will be calculated based on individual utility members and billed to the JOE and designated for each eligible utility.

2. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the Customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. If the sum of a Customer's May to September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a true-up calculation is not applicable. However, if the sum of a Customer's May to September measured irrigation load is less the sum of the May through September billed irrigation load amounts, a true-up calculation is required. The actual metered irrigation kilowatthour (kWh) amounts submitted by the Customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts. The true-up calculation determines the amount of excess Irrigation Rate Discount that a Customer shall reimburse to BPA.

If a true-up calculation is needed, an adjustment shall be determined following each Fiscal Year of the Rate Period and will appear as a charge on the Customer's power bill.

If applicable, the true-up is calculated as follows: The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the true-up reimbursement.

To ensure the timeliness of a true-up reimbursement each eligible Customer must send its May to September measured irrigation load amounts to BPA by October 31 following each May to September irrigation season.

I. Load Shaping Charge True-up Adjustment

The Load Shaping Charge True-up Adjustment is applicable to Customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and will appear on the Customer's power bill.

1. Load Shaping Charge True-up Rate

FY	***Rate in mills/kWh***
2012	6.45
2013	6.45

2. Load Shaping Charge True-up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each Customer determines whether the Customer may be eligible for a True-up charge or credit.

$$\text{Annual Deviation} = \begin{array}{c}\text{Actual Annual Tier 1 Load (measured)} \\ \textit{minus} \\ \text{TOCA Load (calculated)}\end{array}$$

TOCA Load is the annual amount of energy that is used to calculate the Customer's TOCA. If the Customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.T, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-up; see Special Implementation Provision, section 3 below.

(b) True-up Credit

If Annual Deviation is positive, the Customer is eligible for a True-up credit if Above-Forecast Amount is positive (greater than zero).

		RHWM (calculated)
Above-Forecast Amount	=	*minus*
		TOCA Load (calculated)

If Above-Forecast Amount is positive, the True-up Credit billing determinant equals the lesser of:

(1) Annual Deviation multiplied by a negative one (-1), or
(2) Above-Forecast Amount multiplied by a negative one (-1).

There is no True-up if Above-Forecast Amount equals zero (0).

(c) True-up Charge

If Annual Deviation is negative, the Customer may be subject to a True-up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation (< |Annual Deviation|), the Customer is subject to a True-up charge.

		Absolute value of the Annual Deviation (|Annual Deviation|)
True-up Charge billing determinant	=	*minus*
		Above-RHWM Load

The True-up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

(a) the Customer has Above-RHWM load
and
(b) the Customer has an Above-Forecast Amount greater than zero.

If these conditions are met, the Customer may be eligible for an additional Load Shaping True-up credit.

If the Annual Deviation is negative or equal to zero and the absolute value of the Annual Deviation is less than the Customer’s Above-RHWM load, then the Special True-up Credit billing determinant is the smallest of: i) the Customer’s Above-RHWM load; ii) the Above-RHWM load minus the absolute value of the Annual Deviation; or iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-up Credit billing determinant is negative one (-1) multiplied by the lesser of i) the Customer's Above-RHWM load; or ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-up Adjustment

The Load Shaping Charge True-up Adjustment is equal to the Load Shaping Charge True-up rate multiplied by the sum of i) the True-up Credit billing determinant; ii) the True-up Charge billing determinant; and iii) the Special True-up Credit billing determinant.

J. Low Density Discount (LDD)

1. Application and Definitions

For eligible Customers, as defined in section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-12 Composite Customer charge, PF-12 Non-Slice Customer charge, PF-12 Load Shaping charge, and PF-12 Demand charge. It also applies to eligible Customers under the PF-12 Melded rate schedule and the NR-12 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.J.

For Load Following purchases, the applicable discount percentage will apply to all charges for purchases by the Customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, and Demand charge). The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

For Slice/Block purchases, an LDD dollar benefit will be calculated by BPA as though it was a Load Following Customer. BPA will use the Customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the Customer's monthly power bills over the next 12 months. There will be no separate Slice and Block LDD benefits calculated. The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

The eligible and applicable discount percentages shall be revised annually based on data supplied by June 30 of each calendar year (CY) for the previous calendar year and shall become effective on the following October 1.

The calculation of the ratios below shall be based on calendar year data the Customer provides from its annual financial and operating reports (Rural Utility Services Form 7, similar Cooperative Finance Corporation form, or audited financial report) and its annual 861 report to the Energy Information Administration. The annual financial and operating reports and Energy Information Administration reports are to be enclosed with the Customer's calendar year data. The Customer shall certify that the data submitted is true and correct.

Load acquired by a Customer as a direct result of retail access rights established by Federal, state, or local legislation, and that would not otherwise have been acquired absent such legislation, is not eligible to receive the benefits provided by the LDD. The Customer shall certify that the data submitted does not include such load. The Customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the Customer based on the Customer's entire electric utility system in the Pacific Northwest. For Customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Customer separately on the Customer's system in the PNW and on the Customer's entire electric system, both inside and outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the Customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Customer's eligibility for the LDD shall be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a Customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios, the Customer shall be ineligible for the LDD effective the following October 1. The Customer may reapply for the LDD in any subsequent year.

If a Customer's data and reports are submitted prior to the June 30 deadline, and a revision is necessary, the Customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatthour/Investment Ratio

The Kilowatthour/Investment (K/I) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The K/I ratio is calculated by dividing the Customer's Total Retail Load during the previous calendar year by the value of the Customer's depreciated electric plant (excluding generation plant) at the end of the previous calendar year.

(b) The Consumers/Mile of Line Ratio

The Consumers/Mile of Line (C/M) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the Customer's number of consumers within the distribution system, as defined below, by the end-of-CY number of pole miles of distribution lines at the end of the previous calendar year.

Consumers will be the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) should be counted on the basis of the number of residences served. If one meter serves two residences, then two consumers should be counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential Customer will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting should be counted by the number of billings, regardless of the number of lights per billing.

Distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5kV or below to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

2. Eligibility Criteria

To qualify for a discount, the Customer must meet all five of the following eligibility criteria:

(a) The Customer must serve as an electric utility offering power for resale to retail consumers.

(b) The Customer must agree to pass the benefits of the discount through to its eligible Consumers within the region served by BPA.

(c) The Customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 35.96 mills/kWh for FY 2012 and FY 2013.

(d) The Customer's K/I ratio must be less than 100.

(e) The Customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a Customer is eligible for a discount. Such determination shall not be dependent on whether the Customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount Percentage

For each Customer, an eligible discount percentage will be determined using Table D below. The eligible discount percentage will be the sum of the two potential discount percentages for which the Customer qualifies, based on Table D. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to sections 4, 5, and 6 below.

Table D
LDD Percentage Eligible Discount Percentage Table

Percentage Discount	***Applicable Range for kWh/Investment (K/I) Ratio***	***Applicable Range for Consumers/Mile (C/M) Ratio***
0.0%	***35.0 < X***	***12.0 < X***
0.5%	***31.5 < X < 35.0***	***10.8 < X < 12.0***
1.0%	***28.0 < X < 31.5***	***9.6 < X < 10.8***
1.5%	***24.5 < X < 28.0***	***8.4 < X < 9.6***
2.0%	***21.0 < X < 24.5***	***7.2 < X < 8.4***
2.5%	***17.5 < X < 21.0***	***6.0 < X < 7.2***
3.0%	***14.0 < X < 17.5***	***4.8 < X < 6.0***
3.5%	***10.5 < X < 14.0***	***3.6 < X < 4.8***
4.0%	***7.0 < X < 10.5***	***2.4 < X < 3.6***
4.5%	***3.5 < X < 7.0***	***1.2 < X < 2.4***
5.0%	***X < 3.5***	***X < 1.2***

4. LDD Phase-In Adjustment

If the Customer satisfies the eligibility criteria (2.a. through e.) and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage will be one of the following amounts:

(a) the existing eligible discount percentage plus a maximum of one-half percent if the calculated eligible discount percentage exceeds the existing discount.

(b) the existing eligible discount percentage minus a maximum of one-half percentage if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula will be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The Customer is not eligible to receive any discount, effective each October, if the Customer fails to meet the eligibility criteria in section 2.(a) through (e) above. If the Customer is eligible to receive a discount in a year following a year in which the

Customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above will apply to the most-recent eligible discount.

5. Additional Adjustment for Very Low Densities

If a Customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the eligible discount percentage pursuant to sections 3 and 4 above, an additional one-half percentage shall be added to the Customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent. In subsequent years, the one-half percentage added to the eligible discount percentage pursuant to this section shall not be included when determining the applicable discount percentage pursuant to section 4 above.

6. Applicable Discount for Customers with Above-RHWM Load

A discount is not provided for the costs of power used to serve the Customer's Above-RHWM load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM load was included. This adjustment modifies the Customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the Customer's power bill during the rate period is:

$$applicableLDD = eligibleLDD \times \max\left(\frac{adjTRL}{RHWM}, 1.0\right)$$

Where:

applicableLDD = the discount percentage to be applied to the Tier 1 charges on a Customer's bill

eligibleLDD = the Customer's eligible discount percentage as computed according to sections 2 through 5 above.

adjTRL = the Customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the BP-12 Final Proposal for the applicable fiscal year

RHWM = the Customer's Rate Period High Water Mark

Any Customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. Treatment for Joint Operating Entity

The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 Demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility member under the Tier 1 rates according to section 1 above. The monthly LDD benefit for Demand for a JOE is calculated as follows:

(a) each individual utility member's Demand billing determinant is calculated as if such member were not a member of a JOE;

(b) the Demand billing determinants for all individual utility members are summed;

(c) the individual utility members' calculated Demand billing determinants are scaled (up or down) such that the sum of all individual utility members' calculated Demand billing determinants equals the JOE's Demand billing determinant;

(d) the Demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled Demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 Demand charge; and

(e) the Demand LDD benefits of the eligible individual members of the JOE are summed to yield the Demand LDD benefit to the JOE.

K. NFB Mechanisms

The two NFB mechanisms described here are rate features that allow BPA to recover additional revenue if financial impacts ("Financial Effects") from a specified set of circumstances ("Trigger Events") in the fish and wildlife arena cause a reduction in Power Services' forecast Net Revenue. The first mechanism, the NFB Adjustment, would increase the CRAC Cap applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event (see below) occurs. The second mechanism, the Emergency NFB Surcharge, would increase rates within the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The latter situation would apply if waiting until the next year for additional cost recovery would be imprudent because BPA is in a "cash crunch" (defined in section 3 below).

1. Definitions

(a) An NFB *Trigger Event* is one of the following events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those adopted in the most recent wholesale power rate proceeding as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding an FCRPS Biological Opinion (BiOp) issued by NMFS (also known as NOAA Fisheries Service), or any appeal thereof ("Litigation").

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

(3) A new FCRPS BiOp.

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

(5) Actions or measures required under the Adaptive Management Implementation Plan associated with the FCRPS BiOp that reduce BPA's forecast net revenue.

(b) Financial Effects of a Trigger Event are net reductions in estimated Power Net Revenue within the fiscal year due to a Trigger Event that affects power sales revenues, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, USACE and Reclamation O&M expenses, direct program expenses of the USFWS, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations adopted in the most recent wholesale power rate proceeding, as modified prior to this Trigger Event. These effects are the total effects on the BPA System, excluding the operational or expense effects borne by Slice Customers.

(c) The *Agency Within-Year TPP* is the probability that the Agency (including both Power and Transmission) will be able to meet all Agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurs. Agency Within-Year TPP takes into account, for the remainder of such fiscal year: (i) all funds reasonably expected to be available to the Agency to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), any expense reductions and revenue increases, short-term borrowing available through the Treasury Facility (which availability may be limited by constraints on BPA's remaining borrowing authority), and BPA's then-current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the BP-12 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.

(d) *Surcharge Amount* is the amount of money to be collected under the Emergency NFB Surcharge.

(e) *Revenue Basis* is the 12-month totals of revenue from Power rates subject to the Emergency NFB Surcharge for a specific fiscal year.

(f) *Customer Percentage* is the Revenue Basis associated with each Customer divided by the total Revenue Basis. Each Customer Percentage will be rounded to four decimal places.

2. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the BP-12 rates, the NFB Adjustment calculation can result in an increase in the annual CRAC Cap set forth in Table B in GRSP II.C if an NFB Trigger Event occurs prior to the fiscal year to which a CRAC is applied.

NFB Adjustment = Financial Effects of Trigger Event(s)

Adjusted CRAC Cap = CRAC Cap from Table B + NFB Adjustment

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified rates during a year in which (a) Financial Effect(s) occur from a Trigger Event(s) and (b) the Agency Within-Year TPP is below 80 percent (also referred to as a "cash crunch"). A "cash crunch" means the Agency Within-Year TPP is calculated to be below 80 percent including (1) the Financial Effects of all Trigger Events and (2) all revenues from those, but only those, CRACs and Emergency NFB Surcharges that have already been implemented (*i.e.*, calculated, and scheduled to be affecting rates). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

For the BP-12 rates, the Surcharge may be implemented in FY 2012 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2013 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

There can be more than one Trigger Event in a year, and therefore there could be more than one Surcharge implemented in a fiscal year.

At the discretion of the Administrator, BPA may collect the Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

No Surcharge will be levied if the Surcharge Amount described below is calculated to be less than $10 million. If the first month in which the Surcharge bill is sent out occurs during the last quarter of the fiscal year in which the Trigger Event occurred, then the Surcharge Amount in each such month shall not exceed $25 million.

If Surcharge revenues total less than the total Financial Effects for Trigger Events in that year, the remaining balance of Financial Effects will be included in an NFB Adjustment to the CRAC Cap for the subsequent year.

4. Calculations for the NFB Emergency Surcharge

(a) Calculating the NFB Surcharge Amount

NFB Surcharge Amount = Financial Effects of Trigger Event

(b) Calculating the PF/IP/NR Surcharge Amount and the ACS Surcharge Amount

The PF/IP/NR Surcharge Amount is 96.4% times the Surcharge Amount.

The ACS Surcharge Amount is 3.6% times the Surcharge Amount.

(c) Converting the PF/IP/NR Surcharge Amount to the PF/IP/NR Surcharge

Once the PF/IP/NR Surcharge Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to the IP and NR rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate (making a negative Non-Slice Customer rate less negative).

The PF/IP/NR Surcharge rate is calculated by dividing the PF/IP/NR Surcharge Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable months of the applicable year.

The PF/IP/NR Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by multiplying the sum of PF System Shaped Loads for the applicable months by the PF/IP/NR Surcharge rate. The product of this calculation is the dollar amount to be collected through the Non-Slice TOCA billing determinant. The dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by the applicable months in the fiscal year. The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) Customer Charges for the PF/IP/NR Surcharge

Line items will be added to the bills during the applicable months of the applicable year for service under PF Melded, IP, and NR rates showing additional charges calculated by multiplying the PF/IP/NR Surcharge rate by the applicable kilowatthours of service.

A line item will be added to the bills during the applicable months of the applicable year for service under PF rates showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS Surcharge Amount to Charges on Customers' Bills

Once the ACS Surcharge Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H for details of how those Transmission rates subject to the Surcharge will be modified.

(f) Other Rate Adjustments

The PF/IP/NR Surcharge rate will be converted to an annual Surcharge rate. This annual Surcharge rate is calculated as the PF/IP/NR Surcharge rate multiplied by the quotient of the sum of PF System Shaped Loads for the applicable surcharge months divided by the annual sum of PF System Shaped Loads.

The annual Surcharge rate will be applied to the Load Shaping True-up Rate to create the Surcharge-Adjusted Load Shaping True-up Rate. The annual Surcharge rate will be applied to the PF Melded Equivalent Energy Scalar, see GRSP II.R., to create the Surcharge-adjusted PF Melded Equivalent Energy Scalar.

The PF/IP/NR Surcharge will also be applied to the applicable months of the PF Tier 1 Equivalent energy rates. See GRSP II.M.

5. Criteria for Applying the NFB Adjustment or Assessing the Surcharge

NFB Trigger Events that have Financial Effects can lead to NFB Adjustments or Surcharges according to these GRSPs if they occur in fiscal years 2011, 2012, or 2013. Whether such Trigger Events lead to NFB Adjustments or to Surcharges depends on whether BPA is in a "cash crunch" in the year in which the Trigger Event occurs.

If a Trigger Event occurs in FY 2011, it may result in a Surcharge for FY 2011 if BPA is in a cash crunch in FY 2011. Such a Surcharge would be governed by the WP-10 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the

WP-10 GRSPs during FY 2011 collects less than the full amount of the FY 2011 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the CRAC Cap applicable to FY 2012 and 2013, as governed by these GRSPs.

If a Trigger Event occurs in FY 2012, it may result in either a Surcharge applicable to FY 2012 rates or an NFB Adjustment to the CRAC Cap applicable to FY 2013 rates. Such a Trigger Event may result in both NFB mechanisms being used if some but not all of the Financial Effects were recoverable from a Surcharge in FY 2012. All of these possibilities will be governed by these GRSPs.

If a Trigger Event occurs in FY 2013 and BPA is in a cash crunch, the Surcharge procedures defined in these GRSPs will apply. If BPA is not in a cash crunch in FY 2013, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2014 rates based on Trigger Events occurring in FY 2013 will be defined by the 2014 GRSPs.

If a Trigger Event occurs that has Financial Effects in the year of its occurrence and also in later years, the Trigger Event will be deemed to have occurred on the first day of all subsequent years in which it has Financial Effects (*i.e.,* Financial Effects that have not been incorporated into the general rates applicable to that year). If there are, or are deemed to be, multiple Trigger Events in any fiscal year, the Financial Effects of those events will be the net effect for that fiscal year of all Trigger Events combined.

6. NFB Adjustment and Surcharge Notification Processes

BPA shall use the following procedures following a Trigger Event:

(a) Notification of Trigger Event and Related Workshops

BPA will notify Customers within 30 days of the occurrence of an NFB Trigger Event in FY 2012 or 2013, as defined above, if BPA estimates the Financial Effects of the Trigger Event to be $10 million or more. This initial notification, posted to BPA's Web site and provided by e-mail to those listed on the service list for the BP-12 rate proceeding, will include a description of the Trigger Event. BPA may elect not to notify Customers of the Trigger Event if BPA estimates the Financial Effects of a Trigger Event to be less than $10 million or BPA expects that neither a CRAC applicable to the subsequent year nor a Surcharge resulting from the Trigger Event applicable to the current year will be implemented.

If BPA does not determine that the Agency Within-Year TPP is below 80 percent at any later time in the fiscal year, a Trigger Event with Financial Effects will result in an NFB Adjustment. The Financial Effects of the Trigger Event will be presented along with the forecast of the end-of-year ANR calculation in July 2011 or September 2012. There can be more than one NFB Adjustment Trigger Event in a year. There will be only one, if any, calculation of the NFB Adjustment to the CRAC Cap applicable to the next year.

If the ANR is forecast to fall below the CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the CRAC procedures in GRSP II.C. At the workshop(s), BPA will explain the Trigger Event and the estimated Financial Effects. BPA will provide and explain the data, models, and assumptions used to calculate the Surcharge Amount. BPA will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the Customers' request, BPA Account Executives shall provide Customers details of their charges under the Surcharge.

If the CRAC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap. If the CRAC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap.

(b) Notification of Agency Within-Year TPP Falling Below 80 Percent Following a Trigger Event, and Related Workshops

If, during a fiscal year in which a Trigger Event has occurred, BPA determines that the Agency Within-Year TPP is below 80 percent, BPA will notify Customers within seven (7) days of such a determination. In addition, this notification will be posted to BPA's Web site and provided by e-mail to parties on the service list for the BP-12 rate proceeding.

This notification will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notification. This notification will also include updated calculations of the Financial Effects of the Trigger Event(s) and the Agency Within-Year TPP. Concurrently, BPA's Account Executives will inform Customers of their charges under the Surcharge.

At this workshop, BPA will explain the calculation of the Agency Within-Year TPP and the Surcharge Amount, including the monthly shape of payments.

BPA will provide data and assumptions used in these calculations. BPA will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(1) Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notification to each Customer in accordance with the notification provisions of the Customer's BPA contract no later than seven (7) days following the conclusion of the workshop described above. Such Final Notification will state the monthly Surcharge Amount and the total Surcharge Amount to be recovered from each Customer by September 30 of the fiscal year in which the Surcharge is in effect.

The monthly Surcharge Amount will be included on bills to Customers and will be payable in accordance with the applicable payment provisions of the Customers' contracts. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

(2) Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notification of implementation of a Surcharge described above, BPA will convene two or more meetings within sixty (60) days of the Final Notification.

At the first meeting, Customers and interested persons may request additional information and explanations about the Trigger Event, its Financial Effects, and the updated Agency Within-Year TPP. Customers and interested persons may also request information regarding BPA's financial performance to date, revenue and expense forecasts for the remainder of the fiscal year, the calculation of the Surcharge Amount, and any other materials related to the Surcharge then in effect. BPA will provide responses to relevant information requests as promptly as possible, but in any case no later than 48 hours prior to the final meeting. Subsequent meetings may be held as necessary.

At the final meeting, Customers and interested persons may ask questions of and present their views to the Administrator. Customers and interested persons may also submit their views in writing to the Administrator within seven days after the meeting.

Based on the information and views presented during the process provided for in this section, and not later than twenty (20) days after the final meeting, the Administrator will issue a close-out letter that addresses the issues raised in the meetings, the need for the Surcharge, and whether the Surcharge is set at the appropriate level, all in accordance with these GRSPs. If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to Customers for the amounts over-collected, or adjust the Surcharge then in effect for the remainder of the year. The Administrator may remove the Surcharge entirely if one or both of the following occurs:

(a) the Agency Within-Year TPP, not including future surcharge payments, is determined at the time of the close-out letter to be greater than 90 percent; or

(b) an updated calculation indicates that the Financial Effects of the Trigger Event(s) are less than $10 million for that fiscal year.

L. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a Customer purchasing Firm Requirements Power charged under section 2.1 of the PF-12 rate schedule may agree to a PF-12 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-12 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual Customer requests to "shape" certain PF-12 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the Customer. The shaped payments at PF-12 Tier 1 Customer rates will be mutually agreed to by BPA and the Customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2011.

This Shaping Option analysis will take into account the cash-flow impacts to the Customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly Demand charges; and any applicable rate discounts. BPA and the Customer may agree to 12 monthly Composite Customer charges that the Customer shall pay in each year of the rate period. If further shaping is requested to mitigate a Customer's cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping; and

2. The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

M. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

Month	Rate in mills/kWh Diurnal Period: HLH	LLH	Rate in $/kW Demand HLH
October	31.41	24.75	9.18
November	31.92	24.95	9.31
December	34.65	26.94	9.97
January	33.58	25.25	9.70
February	34.48	26.72	9.92
March	33.12	25.88	9.60
April	31.08	23.96	9.10
May	28.61	17.95	8.50
June	29.52	16.57	8.72
July	35.62	23.46	10.20
August	37.90	25.70	10.75
September	37.00	27.14	10.53

N. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are determined pursuant to the definition of Residential Load in section 2 of the 2012 REP Settlement.

Table E
Residential Load (in kWh)

Month	*Avista*	*Idaho*	*North-Western*
October	249,810,193	411,752,689	45,053,181
November	294,369,391	374,139,148	53,013,504
December	405,249,003	526,501,227	65,750,872
January	482,235,005	621,920,898	68,951,808
February	411,828,020	529,646,938	62,445,641
March	373,871,167	480,243,730	55,550,599
April	332,605,442	432,185,665	52,102,953
May	284,929,919	382,203,401	47,304,632
June	257,297,251	408,844,581	45,721,951
July	249,682,902	434,734,263	47,222,571
August	293,905,738	543,959,182	50,200,574
September	269,747,266	486,753,325	46,956,133

Month	*PacifiCorp*	*Portland General*	*Puget Sound*
October	623,530,820	590,678,816	793,638,840
November	693,870,052	673,821,224	989,756,383
December	993,780,172	916,232,241	1,318,881,901
January	1,086,985,340	1,027,721,506	1,447,513,479
February	867,207,780	856,740,142	1,254,203,500
March	792,566,054	804,371,890	1,174,450,000

Month	PacifiCorp	Portland General	Puget Sound
April	720,239,821	721,054,615	1,054,412,000
May	666,108,174	626,117,293	910,425,000
June	674,308,730	609,842,075	806,213,894
July	790,781,448	618,801,197	755,651,416
August	852,923,496	698,783,779	762,008,380
September	706,512,592	632,179,453	776,977,227

These loads are applicable to each year of the rate period, FY 2012-2013, and will be revised pursuant to the 2012 REP Settlement.

O. Residential Exchange Program 7(b)(3) Surcharge Adjustment

1. ASC Adjustment

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-12 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3) Surcharge is displayed in the table in section 6.1 of the PF-12 rate schedule and is subject to modification under this GRSP.

Under the 2008 Average System Cost Methodology, when a participating utility files an ASC with BPA, the utility may request an ASC modification based on the expectation that its set of resources will change during BPA's rate period. The participating utility must file the expected changes to its ASC with its ASC filing. Subject to limitations in the 2008 ASC Methodology, BPA will establish a modified ASC for a utility during BPA's rate period effective with the operational date of the new resource. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in section 6.1 of the PF-12 rate schedule, BPA will adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges will be accomplished by substituting all modified ASCs and recomputing the rates in section 6.1 of the PF-12 rate schedule. This recomputation will be accomplished by:

- Inserting the participating utility's revised Average System Cost, expressed in mills/kWh (equivalent to $/MWh).
- Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-12 7(i) proceeding.
- Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.

- Summing the unconstrained benefits for each participant to compute total unconstrained benefits.
- Computing the difference between the total unconstrained benefits and $403,320,000 (the total REP benefits adopted for the 2-year rate period in the BP-12 7(i) proceeding).
- Allocate the computed difference to participants such that $153,075,234 is allocated to the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.
- Recompute the IOU adjustments specified in section 6.2 of the 2012 REP Settlement.
- Divide the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and add each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Table 2.4.12 of the Power Rates Study Documentation, BP-12-FS-BPA-01A. This table will be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges will take effect on the day that the utility's modified ASC takes effect. This adjustment will occur as frequently as ASCs are modified during the 2-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges will be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program Web site.

2. Change in Service Territory due to Annexation or Load Transfer

Should an REP-participating utility lose or gain load through an annexation or other transfer of load, the total REP benefits of $403,320,000 used in the 7(b)(3) Surcharge calculation in section 1 above will be subject to change. If load is transferred from a participating utility to a preference Customer, resulting in an increase in PF preference load on BPA, and thereby increasing BPA's expenses, then the reduction in REP benefits to the REP-participating IOU will reduce the $403,320,000 by the same amount. If the load is transferred from a participating utility to another Customer such that BPA expenses are not increased due to the transferred load, then the $403,320,000 will not be reduced. The $403,320,000 cannot be increased through a transfer of load.

P. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA Web site.

1. Diurnal Flattening Service Charges, Resource Shaping Charge, and Resource Shaping Charge Adjustment

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service. Unless stated otherwise, the resource amounts used in these calculations are either 1) generation amounts specified in the Customer's CHWM Contract Exhibit A (Exhibit A amounts); or 2) planned generation amounts based on hourly generation from the most recent historical year specified in Exhibit D (Exhibit D amounts).

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's Rate Analysis Model calculates the DFS Energy rate for each resource. Generally, for each monthly/diurnal period, the sum of planned generation in excess of average monthly/diurnal Exhibit D amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in section 1(c) below. The monthly/diurnal results are summed for the year and divided by the total planned energy from the Exhibit D amounts to calculate the DFS Energy rate.

(2) DFS Energy Billing Determinant

The DFS Energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag.

(3) DFS Energy Charge

For each resource, the DFS Energy charge is the product of multiplying the DFS Energy rate by the DFS Energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 Demand rates shown in section 2.1.2.1 of the PF-12 rate schedule.

(2) DFS Capacity Billing Determinant

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

The RSS module of BPA's Rate Analysis Model calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) DFS Capacity Charge

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

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

or

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

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the Customer's CHWM Contract.

(c) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in section 2.1.3.1 of the PF-12 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the annual average Exhibit A amounts for the same year. Generally, the Resource Shaping charge does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract.

(3) Resource Shaping Charge

For each resource, the Resource Shaping charge is the product of multiplying the Resource Shaping rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge.

(d) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and UAIs in the determination of actual generation.

(3) Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is the product of multiplying the Resource Shaping rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

2. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following Customer that dedicates the entire output of a hydroelectric Existing Resource with a credit for the energy produced by that resource that is in excess of the amounts specified in the CHWM Contract Exhibit A (Exhibit A amounts) and a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 Demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual, metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) SCS Energy Billing Determinant

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

(3) SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is the product of multiplying the SCS Energy rate by the SCS Energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the Customer will receive a credit. If the actual generation is less than the Exhibit A amount, the Customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 Demand rate shown in section 2.1.2.1 of the PF-12 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

(3) SCS Administrative Charge

For each resource, the SCS Administrative charge is the product of multiplying the SCS Administrative rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the Customer’s CHWM Contract.

3. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to Customers that have a qualifying resource that experiences a forced outage. Unless stated otherwise, the resource amounts used in these calculations are those specified in the Customer’s CHWM Contract Exhibit D (Exhibit D amounts) and are planned generation amounts based on hourly generation from the most recent historical year.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	***Rate in $/kW***
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity Billing Determinant, section 1(b)(2).

(3) FORS Capacity Charge

For each resource, the FORS Capacity charge is the product of multiplying the FORS Capacity rate by the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the Customer's CHWM Contract.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement) during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

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

(3) FORS Energy Charge

For each resource, the monthly FORS Energy charge is the product of multiplying the FORS Energy rate by the FORS Energy billing determinant.

4. Transmission Scheduling Service Charge and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the Customer. Transmission Curtailment Management Service (TCMS) is a feature of TSS under which BPA provides either replacement transmission or power to Customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) TSS Charge

(1) TSS Rate

FY	***Rate in mills/kWh***
2012	0.23
2013	0.23

(2) TSS Billing Determinant

The TSS billing determinant is the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract.

(3) TSS Charge

For each eligible resource, the TSS charge is the product of multiplying the TSS rate by TSS billing determinant for each month of the rate period (or FY 2013 if this service applies only in FY 2013). The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge. The charge is subject to a cap such that if the annual cost to the Customer using the TSS rate exceeds $1,080/month, then the monthly charge is capped at $1,080/month.

(b) TCMS Charge if Replacement Power is Provided

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS Energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) TCMS Charge

For each eligible resource, the TCMS charge is the product of multiplying the TCMS rate by the TCMS billing determinant for each hour of the month.

(c) TCMS Charge if Alternative Transmission is Provided

(1) TCMS Charge

When replacement Point-to-Point transmission is used to deliver the Customer's eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

Q. RHWM Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in section 2.1.3.2 of the PF-12 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC values for the FY 2012-2013 rate period are shown in Table F below.

Table F
FY 2012-2013 RHWM Tier 1 System Capability

Month	***RT1SC in kWh Diurnal Period: HLH***	***LLH***
October	2,961,235,239	1,678,579,553
November	3,502,848,559	2,177,926,566
December	3,481,759,080	2,182,731,814
January	3,426,187,607	2,261,397,688
February		
2012	2,903,311,798	1,828,509,446
2013	2,788,415,894	1,771,061,494
March	2,889,552,246	1,877,177,196
April	2,229,763,533	1,497,063,764
May	4,131,953,165	2,496,552,914
June	3,591,719,178	1,996,068,864
July	4,006,184,756	1,953,943,898
August	3,319,571,128	1,739,677,390
September	3,117,743,858	1,824,810,716

Note: Monthly values are the same for FY 2012 and FY 2013, except for February, due to the 2012 leap year.

R. Slice True-Up Adjustment

Slice Customers will have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment will be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November). See section 2.7 of the TRM, BP-12-A-03.

1. Calculation of the Annual Composite Cost Pool True-Up

Following the end of each fiscal year of the rate period, BPA will

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

(b) divide the difference determined in (a) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM section 5.1.1, based on the Annual Net Requirement process for Slice Customers and the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following Customers; and

(c) multiply the dollar amount in (b) above by each Slice Customer's Slice Percentage for the applicable fiscal year.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year.

(a) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year will be calculated as the sum of:

(1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-12 7(i) process; and

(2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year, and is equal to the forecast sum of TOCAs for Slice Customers, adjusted based on the Annual Net Requirement process in accordance with TRM section 5.1.1, and for Load Following Customers, adjusted based on TRM section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-12 Composite Customer rate.

and

(3) the Change in Unused RHWM Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) × 45.74 mills/kWh.

Actual Unused RHWM = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year)

Forecast Unused RHWM = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable FY (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(b) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year will be calculated as the sum of:

(1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-12 7(i) process;

(2) i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by -1.59 mills/kWh;

and

(3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues will be obtained from BPA data sources

-1.59 mills/kWh is calculated by the equation:
PFMEES – 8.41 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of 6.82 mills/kWh and is subject to the CRAC, the DDC, and the NFB Emergency Surcharge.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table H) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM section 2.7.2, BPA will:

(a) subtract:

(1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period

from

(2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;

and

(b) for each Slice Customer, multiply the resulting difference from (1) above by the ratio of (i) the Customer’s Slice Percentage for the fiscal year in Exhibit K of the

Slice/Block Contract to (ii) the sum of all Customers' Slice Percentages for the fiscal year in all Exhibit K of the Slice/Block CHWM Contracts.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

Table G
Composite Cost Pool True-Up Table

		Audited Actual Data ($000)	FY 2012 forecast ($000)	FY 2013 forecast ($000)
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		$ 306,366	$ 345,945
5	BUREAU OF RECLAMATION		$ 111,972	$ 119,891
6	CORPS OF ENGINEERS		$ 208,700	$ 215,700
8	LONG-TERM CONTRACT GENERATING PROJECTS		$ 25,079	$ 25,832
9	**Sub-Total**		**$ 652,117**	**$ 707,368**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT		$ 21,928	$ 22,148
12	SPOKANE LEGISLATION SETTLEMENT		$ -	$ -
13	**Sub-Total**		**$ 21,928**	**$ 22,148**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING		$ 1,500	$ 1,500
16	WNP-1&3 DECOMMISSIONING		$ 438	$ 448
17	**Sub-Total**		**$ 1,938**	**$ 1,948**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS		$ 2,452	$ 2,704
20	HEDGING/MITIGATION (omit except for those assoc. with augmentation)		$ -	$ -
21	GROSS OTHER POWER PURCHASES (omit, except for those assoc. with Designated BPA System Obligations or Designated BPA Contract Purchases		$ -	$ -
22	**Sub-Total**		**$ 2,452**	**$ 2,704**
23	**Bookout Adjustment to Power Purchases (omit)**			
24	**Augmentation Power Purchases (omit - calculated below)**			
25	AUGMENTATION POWER PURCHASES			
26	**Sub-Total**		**$ -**	**$ -**
27	**Exchanges and Settlements**			
28	RESIDENTIAL EXCHANGE PROGRAM (REP)		$ 210,490	$ 192,656
29	REP ADMINISTRATION COSTS		$ 1,446	$ 885
30	OTHER SETTLEMENTS		$ -	$ -
31	**Sub-Total**		**$ 211,935**	**$ 193,541**
32	**Renewable Generation**			
33	RENEWABLES R&D		$ 5,622	$ 5,939
34	Contra expense for unspent GEP revenues remaining at end of FY 2011		$ (2,625)	$ (2,625)
35	RENEWABLES (excludes KIII)		$ 27,670	$ 28,145
36	**Sub-Total**		**$ 30,667**	**$ 31,459**
37	**Generation Conservation**			
38	GENERATION CONSERVATION R&D		$ -	$ -
39	DSM TECHNOLOGY		$ -	$ -
40	CONSERVATION ACQUISITION		$ 15,950	$ 15,950
41	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000
42	ENERGY EFFICIENCY DEVELOPMENT		$ 11,500	$ 11,500
43	LEGACY		$ 1,000	$ 900
44	MARKET TRANSFORMATION		$ 13,500	$ 14,500
45	**Sub-Total**		**$ 46,950**	**$ 47,850**
46	**Conservation Rate credit (CRC)**		**$ -**	**$ -**
47	**Power System Generation Sub-Total**		**$ 967,988**	**$ 1,007,017**
48				
49	**Power Non-Generation Operations**			
50	**Power Services System Operations**			
51	EFFICIENCIES PROGRAM		$ -	$ -
52	PS SYSTEM OPERATIONS R&D		$ -	$ -
53	INFORMATION TECHNOLOGY		$ 7,143	$ 7,316
54	GENERATION PROJECT COORDINATION		$ 5,895	$ 5,919
55	SLICE IMPLEMENTATION		$ 2,322	$ 2,394
56	**Sub-Total**		**$ 15,360**	**$ 15,629**
57	**Power Services Scheduling**			
58	OPERATIONS SCHEDULING		$ 10,041	$ 10,010
59	PS SCHEDULING R&D		$ -	$ -
60	OPERATIONS PLANNING		$ 6,744	$ 6,709
61	**Sub-Total**		**$ 16,785**	**$ 16,719**
62	**Power Services Marketing and Business Support**			
63	SALES & SUPPORT		$ 19,745	$ 20,130
64	STRATEGY, FINANCE & RISK MGMT		$ 16,469	$ 17,412
65	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 3,480	$ 3,550
66	CONSERVATION SUPPORT		$ 9,555	$ 9,686
67	**Sub-Total**		**$ 49,249**	**$ 50,778**
68	**Power Non-Generation Operations Sub-Total**		**$ 81,393**	**$ 83,126**
69	**Power Services Transmission Acquisition and Ancillary Services**			
70	**PS Transmission Acquisition and Ancillary Services**			
71	POWER SERVICES TRANSMISSION & ANCILLARY SERVICES			
72	Transmission costs for Designated BPA System Obligations		$ 31,707	$ 31,707
73	3RD PARTY GTA WHEELING		$ 52,263	$ 52,891
74	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)			
75	GENERATION INTEGRATION		$ 8,865	$ 8,709
76	WIND INTEGRATION TEAM		$ 4,170	$ 4,259
77	TELEMETERING/EQUIP REPLACEMT		$ 50	$ 51
78	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 97,056**	**$ 97,617**
79	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
80	**BPA Fish and Wildlife (includes F&W Shared Services)**			
81	**Fish & Wildlife**		$ 237,394	$ 241,384
82	**USF&W Lower Snake Hatcheries**		$ 28,800	$ 29,900
83	**Planning Council**		$ 10,114	$ 10,355
84	**Environmental Requirements**		$ 302	$ 305
85	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 276,610**	**$ 281,944**

Table G, continued
Composite Cost Pool True-Up Table

		Audited Actual Data ($000)	FY 2012 forecast ($000)		FY 2013 forecast ($000)
86	**BPA Internal Support**				
87	**Additional Post-Retirement Contribution**		$ 17,243		$ 17,821
88	**Agency Services G&A (excludes direct project support)**		$ 51,735		$ 52,662
89	**BPA Internal Support Sub-Total**		**$ 68,978**		**$ 70,483**
90	**Bad Debt Expense**		$ -		$ -
91	**Other Income, Expenses, Adjustments**		**$ -**		**$ -**
92	**Non-Federal Debt Service**				
93	**Energy Northwest Debt Service**				
94	COLUMBIA GENERATING STATION DEBT SVC		$ 115,553		$ 100,172
95	WNP-1 DEBT SVC		$ 282,802		$ 249,288
96	WNP-3 DEBT SVC		$ 156,299		$ 175,817
97	EN RETIRED DEBT		$ -		$ -
98	EN LIBOR INTEREST RATE SWAP		$ -		$ -
99	**Sub-Total**		**$ 554,654**		**$ 525,277**
100	**Non-Energy Northwest Debt Service**				
101	TROJAN DEBT SVC		$ -		$ -
102	CONSERVATION DEBT SVC		$ 2,379		$ 2,377
103	COWLITZ FALLS DEBT SVC		$ 11,715		$ 11,709
104	NORTHERN WASCO DEBT SVC		$ 2,223		$ 2,224
105	**Sub-Total**		**$ 16,316**		**$ 16,309**
106	**Non-Federal Debt Service Sub-Total**		**$ 570,970**		**$ 541,586**
107	**Depreciation**		$ 122,169		$ 127,560
108	**Amortization**		$ 81,029		$ 86,767
109	**Total Operating Expenses**		**$ 2,266,193**		**$ 2,296,100**
110					
111	**Other Expenses**				
112	Net Interest Expense		$ 208,802		$ 221,546
113	Interest credit adjustment (to remove nonSlice cost pool interest credit)		$ 1,362		$ (1,216)
114	LDD		$ 31,768		$ 32,944
115	Irrigation Rate Discount Costs		$ 19,305		$ 19,305
116	**Sub-Total**		**$ 261,237**		**$ 272,579**
117	**Total Expenses**		**$ 2,527,430**		**$ 2,568,680**
118					
119	**Revenue Credits**				
120	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		$ 127,449		$ 131,078
121	Downstream Benefits and Pumping Power revenues		$ 14,338		$ 14,438
122	4(h)(10)(c) credit		$ 91,062		$ 95,847
123	Colville and Spokane Settlements		$ 4,600		$ 4,600
124	Energy Efficiency Revenues		$ 11,500		$ 11,500
125	Miscellaneous revenues		$ 3,420		$ 3,420
126	Renewable Energy Certificates		$ 2,658		$ 2,836
127	Pre-Subscription Revenues		$ 1,716		$ 1,778
128	Net Revenues from other Designated BPA System Obligations		$ 360		$ 397
129	WNP-3 Settlement revenues		$ 29,516		$ 29,163
130	RSS Revenues		$ 2,532		$ 2,611
131	Firm Surplus and Secondary Adjustment (from Unused RHWM)		$ 19,469		$ 5,827
132	Balancing Augmentation Adjustment		$ (7,957)		$ (6,268)
133	Transmission Loss Adjustment		$ 24,835		$ 25,266
134	Tier 2 Rate Adjustment		$ 215		$ 645
135	NR Revenues		$ 1		$ 1
136	**Total Revenue Credits**		**$ 325,712**		**$ 323,139**
137					
138	**Augmentation Costs (not subject to True-Up)**				
139	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		$ 12,740		$ 12,737
140	Augmentation Purchases		$ -		$ 66,155
141	**Total Augmentation Costs**		**$ 12,740**		**$ 78,892**
142					
143	**DSI Revenue Credit**				
144	Revenues 340 aMW, 340 aMW @ IP rate		$ 108,606		$ 108,309
145	**Total DSI revenues**		**$ 108,606**		**$ 108,309**
146					
147	**Minimum Required Net Revenue Calculation**				
148	Principal Payment of Fed Debt for Power		$ 193,000		$ 122,800
149	Irrigation assistance		$ 1,182		$ 58,822
150	Depreciation		$ 122,169		$ 127,560
151	Amortization		$ 81,029		$ 86,767
152	Capitalization Adjustment		$ (45,937)		$ (45,937)
153	Bond Premium Amortization		$ 185		$ 185
154	Principal Payment of Fed Debt exceeds non cash expenses		$ 36,736		$ 13,047
155	Minimum Required Net Revenues		**$ 36,736**		**$ 13,047**
156					
157	Annual Composite Cost Pool (Amounts for each FY)		**$ 2,142,588**		**$ 2,229,172**
158					
159	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**				
160	TRUE UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)				
161	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)				
162	TRUE-UP ADJUSTMENT CHARGE BILLED (26.85407 percent)				

Table H
Slice Cost Pool True-Up Table

		Audited Actual Data ($000)	FY 2012 forecast ($000)		FY 2013 forecast ($000)	
1	**Slice Expenses**					
2						
3						
4	**Total Slice Expenses**		$ -		$ -	
5						
6	**Slice Credits**					
7						
8	**Total Slice Credits**		$ -		$ -	
9						
10	Annual Slice Cost Pool (Amounts for each FY)		$ -		$ -	
11						
12	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL**					
13	TRUE UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)					
14						
15	TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)					

S. Tier 2 Rate TCMS Adjustment

When BPA provides replacement power during a transmission event, a TCMS adjustment will be applied to Customers' bills if they purchase power at the applicable Tier 2 rate. The megawatthours of replacement power will be multiplied by the applicable Powerdex Mid-C hourly index price (or its replacement) for the hour(s) the event occurred. If a Mid-C price is less than zero, the TCMS Adjustment rate will be zero for that hour. The sum of this calculation every month is the Tier 2-related TCMS cost. Each Tier 2 rate Customer's TCMS Adjustment will be the Customer's share of the Tier 2-related TCMS cost allocated by total applicable Tier 2 rate sales.

T. TOCA Adjustment

For each Customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-12 7(i) process and will be made available to the Customer prior to October 1, 2011. A Customer's TOCA for a fiscal year will be revised only as specified below. Any adjustment of a Customer's TOCA must be made prior to each October 1 and is effective for the following fiscal year only.

1. Load Following Customers

If there is substantial reason for BPA to believe that the Customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the 2011 CHWM Process, BPA will calculate an Adjusted TOCA for that Load Following Customer using an updated estimate of the Customer's Actual Annual Tier 1 Load in place of the Customer's Forecast Net Requirement, as follows:

$$\frac{\text{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWMs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-12 7(i) process by at least 20 percent, this Adjusted TOCA will be used in the place of the TOCA calculated in the BP-12 7(i) process.

A Load Following Customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

The Customer's Adjusted TOCA will be the billing determinant for the Composite and Non-Slice Customer charges for the relevant fiscal year. No other Customer's TOCA shall be affected by this TOCA adjustment.

2. Slice/Block Customers

BPA will revise the TOCA of a Slice/Block Customer in two circumstances:

(a) If the Customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-12 7(i) process, the Customer's TOCA shall be recalculated for that fiscal year using the Customer's Annual Net Requirement.

(b) If the Customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-12 7(i) process is less than its RHWM, then the Customer's TOCA shall be recalculated for that fiscal year using the Customer's RHWM.

The adjusted TOCA will be used to determine an adjusted Non-Slice TOCA for the relevant fiscal year. No other Customer's TOCA shall be affected by this TOCA adjustment.

U. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2011, that results in an unanticipated increase in a Customer's load placed on BPA during the FY 2012-2013 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a Customer that adds load through retail access, including load that was once served by the customer and returns under retail access. When ULS is used for replacement of a customer's new Specified Resource, ULS is available only on a temporary basis for the FY 2012-2013 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of unanticipated load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-12, unanticipated load is:

- Load of a New Public (Load Following customers only)
- Load annexed from investor-owned utilities by a Public (Load Following customers only)

Under NR-12, unanticipated load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-12, unanticipated load is:

- Delays in the on-line date of a Customer's specified resource for Above-RHWM service (Load Following customers only)
- New Specified Resources that are 10 aMW or less and either experience permanent failure during the rate period or fail to come online (Load Following customers only)
- Transfer customers that both 1) cannot secure Firm Network Transmission (NT) from source to sink for their Dedicated Non-Federal Resource to their Above-RHWM Load by the time power deliveries are to begin under the Regional Dialogue contract and 2) are expected to face high TCMS charges due to their reliance on Secondary Network Transmission, while they pursue Firm Network Transmission (Load Following customers only)

BPA also will review annexations of load between public utility Customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered unanticipated load.

To start service for unanticipated load, a Customer must notify BPA three months in advance of the requested service date for load amounts between 1 and 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for unanticipated load, a Customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the Customer's contract for unanticipated load service or the conclusion of the rate period on September 30, 2013, whichever occurs first. ULS is a temporary service and may be adjusted annually. Any unanticipated load service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Rate Under PF-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh Diurnal Period:***	
	HLH	***LLH***
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

(2) Energy Billing Determinant

The energy billing determinant will be the total amount of unanticipated load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The demand rate is equal to the demand rate included in section 2.1.2.1 of the PF-12 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant will be the lesser of (1) the maximum unanticipated hourly load in a month during the HLH minus the average HLH load amount for the month or (2) 20 percent of the highest unanticipated hourly load amount in a month during the HLH.

3. Unanticipated Load Rate Under the NR-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	***Rate in mills/kWh Diurnal Period:***	
	HLH	***LLH***
October	71.70	65.04
November	72.21	65.24
December	74.94	67.23
January	73.87	65.54
February	74.77	67.01
March	73.41	66.17
April	71.37	64.25
May	68.90	58.24
June	69.81	56.86
July	75.91	63.75
August	78.19	65.99
September	77.29	67.43

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The demand rate is equal to the demand rate included in section 2.2 of the NR-12 rate schedule.

(2) Demand Billing Determinant

The billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the unanticipated NR Hourly Load in a month during the HLH.

4. Unanticipated Load Rate Under the FPS-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the Resource Replacement rate for the applicable diurnal period (shown in the table below), or (2) the applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

Month	*Resource Replacement Rate in mills/kWh Diurnal Period:*	
	HLH	*LLH*
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

Month	*Rate in $/kW*
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

(2) Demand Billing Determinant

The billing determinant is the highest maximum unanticipated resource replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the unanticipated resource replacement load in a month during the HLH.

V. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any Customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during a HLH billing hour that exceeds the amount of demand the Customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand charge.

The billing determinant for the UAI demand charge will be equal to the Customer's single highest HLH demand that is in excess of the Customer's contractual demand entitlement.

For a Load Following Customer, the demand in excess of its demand entitlement will be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the Customer's CHWM Contract Exhibit A amount or Exhibit D amount, whichever is applicable.

For a Slice Customer, the demand in excess of its demand entitlement is any excess Slice delivered amount on the highest Slice delivery hour during the HLH period of the month.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the Customer is contractually entitled to take during a diurnal billing period shall be billed the greater of:

(a) 150 mills/kWh; or

(b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price index expires, the index will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2011, and September 30, 2013.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in section 4 of the Block and Slice/Block CHWM Contracts.

2. Capacity Without Energy

Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. The notice provision may be automated, such as Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity product. No energy is sold with Capacity Without Energy; any energy delivered when the capacity contract is exercised will be returned or paid for under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when capacity rights are exercised.

3. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible Customers under the Priority Firm Power (PF-12), New Resources Firm Power (NR-12), and Firm Power Products and Services (FPS-12) rate schedules. Such power is not available under the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

(a) Power sold for construction is to be used in the construction of the project.

(b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.

(c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.

(d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. Firm Requirements Power

Firm Requirements Power is Federal power that BPA makes continuously available to a Customer to meet BPA's obligations to the Customer under section 5(b) of the Northwest Power Act.

5. Forced Outage Reserve Service (FORS)

As defined in the TRM, FORS is a service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource.

6. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make available to a DSI Customer subject to the terms of the DSI Customer's power sales contract with BPA.

7. Load Following Product

As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the Customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

8. Load Shaping

BPA provides Load Shaping to Customers with CHWM Contracts purchasing either the Load Following Product or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a Customer's Actual Monthly/Diurnal Tier 1 Load.

9. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

(a) for any NLSL, as defined in the Northwest Power Act

(b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA

NR is to be used to meet the Customer's firm power load within the PNW. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

10. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program (REP) may purchase PF pursuant to their RPSA or REPSIA with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

11. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Customer pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that Customer at BPA's PF rate applicable to exchanging utilities (PF Exchange rate). The amount of power purchased and sold are both equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm Customers.

12. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following Customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block Customers contractually dedicate to serving their Total Retail Load. RSS include Diurnal Flattening Service, Forced Outage Reserve Service, Secondary Crediting Service, and Transmission Curtailment Management Service.

13. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the customer applies its resource directly to load and Federal deliveries cover the net load

14. Slice/Block Product

The Slice/Block Product is the Customer's purchase obligation under the Slice product and the Block Product to meet its regional consumer load obligation under section 3.1 of the Slice/Block CHWM Contract.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, NLSLs, and the Customer's RHWM, as determined in the RHWM Process. For the Transition Period, FY 2012-2014, Above-RHWM Load will be established as described in TRM section 4.3.2.2.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the Customer's electric load (measured in kilowatthours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

(a) A measure of electric power usage at a Customer's metered point of delivery used in the computation of a Customer's bill;

(b) as defined in the TRM, a unit of measure for sales of a product or service for which a Customer is billed by BPA.

4. Charge

A charge is the product of a Billing Determinant and a Rate.

5. Contract Demand

The Customer's Contract Demand is the maximum amount of capacity that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each Customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the Customer's Demand charge billing determinant, as calculated in accordance with TRM section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each Customer in accordance with TRM section 4. For each Customer with a CHWM Contract, the CHWM is used to calculate each Customer's RHWM in the RHWM Process for each applicable rate period. The CHWM Contract specifies the CHWM for each Customer.

9. CHWM Contract

As defined in the TRM, the CHWM Contract is the power sales contract between a Customer and BPA that contains a Contract High Water Mark (CHWM), and under which the Customer purchases power from BPA at rates established by BPA in accordance with the TRM.

10. Customer

Pursuant to the terms of an agreement and applicable rate schedule(s), a Customer is the entity that contracts to pay BPA for providing a product or service.

11. DSI Reserve

A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in GRSP II.E, that is provided by a DSI in a contract with BPA.

12. Flat Annual Shape

As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

13. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all hours in the on-peak period – the hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes NERC Standards in classifying six holidays as Light Load Hours.

14. IntercontinentalExchange (ICE) Mid-C Day Ahead Power Price Index

Average HLH (or on-peak) and average LLH (or off-peak) price indices for firm power sales of electricity at delivery points along the Mid-Columbia River, as published by IntercontinentalExchange, Inc.

15. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the hour ending 11 p.m. through the hour ending 6 a.m., Monday through Saturday, and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year; Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

16. Metered Demand

The Metered Demand, in kilowatts, shall be the largest of the 60-minute clock hour integrated demands at which electric energy is delivered to a Customer:

(a) at each point of delivery for which the Metered Demand is the basis for determination of the measured demand;

(b) during each time period specified in the applicable rate schedule; and

(c) during any billing period.

Such largest integrated demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Customer.

17. Metered Energy

The Metered Energy for a Customer shall be the amount of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Customer:

(a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and

(b) during any billing period.

18. Minimum DSI Operating Reserve – Supplemental

The Minimum DSI Operating Reserve – Supplemental is a right to interrupt DSI load made available by each DSI purchasing Industrial Firm Power in a megawatt amount equal to 10 percent of Net Industrial Firm Power. Net Industrial Firm Power shall equal the Industrial Firm Power less the sum of: (a) any power restricted by BPA under any other agreement, and (b) Wheel Turning Load. The availability of the Minimum DSI Operating Reserve – Supplemental must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) standards and criteria:

(a) The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA;

(b) In the event of a system disturbance, the interruptible load or increased generation must be accessible prior to a request for reserves from other NWPP parties;

(c) The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.

(d) There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

The energy charges stated in the IP-12 rate schedule reflect the credit for the value of the Minimum DSI Operating Reserve – Supplemental.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer.

As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of 1) a Customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or 2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to section 5(b) of the Northwest Power Act.

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM section 4.2.1 and expressed in average megawatts, that BPA establishes for each Customer based on the Customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a Customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following Customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block Customers.

24. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the Customer-specific charge or credit as described in TRM section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

25. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

26. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

27. RHWM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHWM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC table of values may be found at GRSP II.Q.

28. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM section 5.3.4, that a Customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

29. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a Customer must reshape its HLH energy from its Specified and Unspecified Resources to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2012-2013 are as follows (HE = Hour Ending):

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

30. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block Customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the Customer's TOCA Load was delivered in the shape of the RHWM Tier 1 System Capability through such periods.

31. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the Customer charges for each Customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM section 5.1.1. TOCAs are posted on BPA's Web site.

32. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the Customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

33. Total Customer System Peak (CSP or Total CSP)

Total Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

34. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a customer's electrical system, excluding: (i) those loads BPA and the customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such customer; or (iii) any loads not on such customer's electrical system or not within such customer's service territory, unless specifically agreed to by BPA.

35. Unanticipated Load

Unanticipated Load is any request by a Customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the Customer's load placed on BPA during the ensuing rate period and (2) was not requested and thus not forecast when setting the rates for that rate period.

36. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a Customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the Customer's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

Appendix A

Customer Refund Amounts in FY 2012-2013

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Customer Refund Amounts in FY 2012-2013

Section 1. Purpose

The Customer Refund Amount in FY 2012-2013 is a credit on a customer's power bill pursuant to the 2012 REP Settlement, Contract No. 11PB-12322 (Settlement). The individual customer credit is determined in part on the terms of the Settlement and in part on information developed in each rate case.

Section 2. Terms of the Customer Refund Amount

The Customer Refund Amount applies to customers listed in the table below.

A credit shall appear on the monthly power bills beginning with the month that the rates established in the BP-12 rate proceeding take effect. The total credit for a given fiscal year will be the fiscal year's Total Refund divided into 12 equal monthly amounts. Monthly amounts shall be rounded to the nearest whole dollar amount on the power bill.

Section 3. Definitions

<u>PF-02 Refund</u> is the portion of the Customer Refund Amount provided pursuant to Exhibit B of the Settlement.

<u>Scaled TOCA</u> is the customer specific percentage derived from a customer's BP-12 Final Proposal TOCA as adjusted pursuant to Section 3.4 of the REP Settlement Agreement.

<u>TOCA Refund</u> is the annual Refund Amount from Section 3.2 of the Settlement ($76,537,617) minus the total annual Customer Specific PF-02 Refund Amount from Exhibit B of the Settlement ($38,269,000) multiplied by the Scaled TOCA or $76,537,617 minus $38,269,000 equals $38,268,617 multiplied by the Scaled TOCA .

<u>Total Refund</u> is the sum of the PF-02 Refund Amount and the TOCA Refund Amount.

Section 4. Customer Refund Amounts

As displayed on the following table:

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10005	Alder Mutual	$ 3,178	0.0080%	0.0079%	$ 3,062	$ 3,029	$ 6,240	$ 6,207
10015	Asotin County PUD #1	$ -	0.0087%	0.0086%	$ 3,321	$ 3,305	$ 3,321	$ 3,305
10024	Benton County PUD #1	$ 1,074,609	2.8284%	2.8274%	$ 1,082,402	$ 1,082,009	$ 2,157,011	$ 2,156,618
10025	Benton REA	$ 365,914	0.9784%	0.9679%	$ 374,437	$ 370,409	$ 740,351	$ 736,323
10027	Big Bend Elec Coop	$ 180,557	0.8823%	0.8846%	$ 337,636	$ 338,528	$ 518,193	$ 519,085
10029	Blachly Lane Elec Coop	$ 102,877	0.2514%	0.2547%	$ 96,195	$ 97,454	$ 199,072	$ 200,331
10044	Canby, City of	$ 146,793	0.2964%	0.2936%	$ 113,439	$ 112,348	$ 260,232	$ 259,141
10046	Central Electric Coop	$ 400,537	1.1423%	1.1530%	$ 437,128	$ 441,226	$ 837,664	$ 841,762
10047	Central Lincoln PUD	$ 483,285	2.2113%	2.2039%	$ 846,231	$ 843,394	$ 1,329,515	$ 1,326,679
10055	Albion, City of	$ -	0.0058%	0.0058%	$ 2,211	$ 2,203	$ 2,211	$ 2,203
10057	Ashland, City of	$ 161,518	0.2941%	0.2926%	$ 112,560	$ 111,959	$ 274,078	$ 273,477
10059	Bandon, City of	$ 55,554	0.1058%	0.1053%	$ 40,472	$ 40,296	$ 96,026	$ 95,851
10061	Blaine, City of	$ 60,506	0.1261%	0.1264%	$ 48,251	$ 48,377	$ 108,757	$ 108,883
10062	Bonners Ferry, City of	$ 45,589	0.0777%	0.0769%	$ 29,747	$ 29,427	$ 75,335	$ 75,015
10064	Burley, City of	$ 105,386	0.2055%	0.2033%	$ 78,649	$ 77,803	$ 184,035	$ 183,189
10065	Cascade Locks, City of	$ 17,913	0.0324%	0.0321%	$ 12,396	$ 12,270	$ 30,309	$ 30,183
10066	Centralia, City of	$ 164,230	0.3516%	0.3523%	$ 134,556	$ 134,823	$ 298,786	$ 299,054
10067	Cheney, City of	$ 108,606	0.2311%	0.2286%	$ 88,452	$ 87,501	$ 197,058	$ 196,107
10068	Chewelah, City of	$ -	0.0401%	0.0411%	$ 15,347	$ 15,736	$ 15,347	$ 15,736
10070	Declo, City of	$ -	0.0052%	0.0052%	$ 2,004	$ 1,983	$ 2,004	$ 1,983
10071	Drain, City of	$ 19,088	0.0309%	0.0311%	$ 11,835	$ 11,893	$ 30,923	$ 30,981
10072	Ellensburg, City of	$ 175,179	0.3505%	0.3467%	$ 134,114	$ 132,671	$ 309,293	$ 307,851
10074	Forest Grove, City of	$ 169,141	0.3530%	0.3512%	$ 135,088	$ 134,395	$ 304,229	$ 303,535
10076	Heyburn, City of	$ 50,558	0.0704%	0.0696%	$ 26,939	$ 26,649	$ 77,497	$ 77,207
10078	McCleary, City of	$ 35,576	0.0610%	0.0603%	$ 23,340	$ 23,089	$ 58,916	$ 58,665
10079	McMinnville, City of	$ 593,568	1.2488%	1.2751%	$ 477,910	$ 487,958	$ 1,071,478	$ 1,081,526
10080	Milton, Town of	$ 53,707	0.1087%	0.1075%	$ 41,590	$ 41,142	$ 95,297	$ 94,849
10081	Milton-Freewater, City of	$ 76,961	0.1375%	0.1374%	$ 52,613	$ 52,594	$ 129,574	$ 129,555
10082	Minidoka, City of	$ -	0.0017%	0.0017%	$ 660	$ 653	$ 660	$ 653
10083	Monmouth, City of	$ 59,603	0.1222%	0.1209%	$ 46,767	$ 46,264	$ 106,370	$ 105,867
10086	Plummer, City of	$ 28,254	0.0577%	0.0570%	$ 22,063	$ 21,826	$ 50,317	$ 50,080
10087	Port Angeles, City of	$ 517,172	1.1982%	1.1887%	$ 458,539	$ 454,892	$ 975,711	$ 972,065
10089	Richland, City of	$ 623,657	1.4413%	1.4614%	$ 551,561	$ 559,243	$ 1,175,218	$ 1,182,900
10091	Rupert, City of	$ 72,943	0.1304%	0.1290%	$ 49,893	$ 49,372	$ 122,836	$ 122,315
10094	Soda Springs, City of	$ -	0.0434%	0.0428%	$ 16,595	$ 16,373	$ 16,595	$ 16,373
10095	Sumas, Town of	$ 23,429	0.0532%	0.0527%	$ 20,369	$ 20,150	$ 43,798	$ 43,579
10097	Troy, City of	$ -	0.0298%	0.0295%	$ 11,394	$ 11,271	$ 11,394	$ 11,271
10101	Clallam County PUD #1	$ 520,583	1.1103%	1.0990%	$ 424,907	$ 420,588	$ 945,490	$ 941,171

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10103	Clark County PUD #1	$ 2,370,948	4.4021%	4.4012%	$ 1,684,623	$ 1,684,286	$ 4,055,572	$ 4,055,235
10105	Clatskanie PUD	$ 617,393	1.2971%	1.2884%	$ 496,398	$ 493,064	$ 1,113,791	$ 1,110,457
10106	Clearwater Power	$ 125,833	0.3361%	0.3368%	$ 128,610	$ 128,887	$ 254,443	$ 254,720
10109	Columbia Basin Elec Coop	$ -	0.1745%	0.1752%	$ 66,791	$ 67,040	$ 66,791	$ 67,040
10111	Columbia Power Coop	$ -	0.0465%	0.0464%	$ 17,804	$ 17,758	$ 17,804	$ 17,758
10112	Columbia River PUD	$ 265,444	0.8204%	0.8184%	$ 313,942	$ 313,189	$ 579,386	$ 578,633
10113	Columbia REA	$ -	0.5508%	0.5449%	$ 210,783	$ 208,516	$ 210,783	$ 208,516
10116	Consol. Irrigation District	$ 1,825	0.0033%	0.0033%	$ 1,273	$ 1,259	$ 3,098	$ 3,084
10118	Consumers Power	$ 246,076	0.6298%	0.6288%	$ 241,027	$ 240,637	$ 487,103	$ 486,713
10121	Coos Curry Elec Coop	$ 229,267	0.5861%	0.5834%	$ 224,277	$ 223,272	$ 453,544	$ 452,540
10123	Cowlitz County PUD #1	$ 3,446,817	7.7193%	7.6630%	$ 2,954,063	$ 2,932,520	$ 6,400,880	$ 6,379,337
10136	Douglas Electric Cooperative	$ 105,338	0.2607%	0.2586%	$ 99,754	$ 98,957	$ 205,093	$ 204,295
10142	East End Mutual Electric	$ -	0.0393%	0.0388%	$ 15,024	$ 14,863	$ 15,024	$ 14,863
10144	Eatonville, City of	$ 23,238	0.0492%	0.0487%	$ 18,834	$ 18,632	$ 42,072	$ 41,870
10156	Elmhurst Mutual P & L	$ -	0.4658%	0.4657%	$ 178,241	$ 178,200	$ 178,241	$ 178,200
10157	Emerald PUD	$ 376,548	0.7320%	0.7398%	$ 280,135	$ 283,105	$ 656,683	$ 659,653
10158	Energy Northwest	$ 20,415	0.0384%	0.0379%	$ 14,682	$ 14,521	$ 35,097	$ 34,935
10170	Eugene Water & Electric Board	$ 1,490,101	3.6391%	3.6298%	$ 1,392,621	$ 1,389,076	$ 2,882,722	$ 2,879,177
10172	U.S. Airforce Base, Fairchild	$ 60,465	0.0871%	0.0872%	$ 33,326	$ 33,384	$ 93,791	$ 93,850
10173	Fall River Elec Coop	$ 152,407	0.4841%	0.4789%	$ 185,268	$ 183,275	$ 337,674	$ 335,681
10174	Farmers Elec Coop	$ -	0.0073%	0.0072%	$ 2,784	$ 2,770	$ 2,784	$ 2,770
10177	Ferry County PUD #1	$ 67,875	0.1679%	0.1686%	$ 64,269	$ 64,530	$ 132,144	$ 132,405
10179	Flathead Elec Coop	$ 608,080	2.3110%	2.3263%	$ 884,380	$ 890,233	$ 1,492,460	$ 1,498,312
10183	Franklin County PUD #1	$ 471,954	1.6676%	1.6844%	$ 638,172	$ 644,584	$ 1,110,125	$ 1,116,537
10186	Glacier Elec Coop	$ -	0.3032%	0.3052%	$ 116,024	$ 116,813	$ 116,024	$ 116,813
10190	Grant County PUD #2	$ 1,146,092	0.6011%	0.5947%	$ 230,043	$ 227,568	$ 1,376,135	$ 1,373,660
10191	Grays Harbor PUD #1	$ 736,828	1.9175%	1.8968%	$ 733,786	$ 725,892	$ 1,470,614	$ 1,462,720
10197	Harney Elec Coop	$ 91,382	0.3228%	0.3236%	$ 123,544	$ 123,828	$ 214,926	$ 215,210
10202	Hood River Elec Coop	$ 89,783	0.1864%	0.1864%	$ 71,336	$ 71,332	$ 161,119	$ 161,115
10203	Idaho County L & P	$ 39,010	0.0908%	0.0898%	$ 34,745	$ 34,372	$ 73,755	$ 73,381
10204	Idaho Falls Power	$ 435,271	1.1402%	1.1385%	$ 436,348	$ 435,698	$ 871,619	$ 870,969
10209	Inland P & L	$ -	1.5108%	1.5217%	$ 578,177	$ 582,320	$ 578,177	$ 582,320
10230	Kittitas County PUD #1	$ 48,061	0.1343%	0.1329%	$ 51,380	$ 50,859	$ 99,441	$ 98,920
10231	Klickitat County PUD #1	$ 219,238	0.5167%	0.5203%	$ 197,719	$ 199,125	$ 416,957	$ 418,363
10234	Kootenai Electric Coop	$ -	0.7218%	0.7266%	$ 276,206	$ 278,058	$ 276,206	$ 278,058
10235	Lakeview L & P (WA)	$ 261,953	0.4751%	0.4714%	$ 181,808	$ 180,387	$ 443,761	$ 442,340
10236	Lane County Elec Coop	$ 154,159	0.4149%	0.4132%	$ 158,782	$ 158,140	$ 312,941	$ 312,299
10237	Lewis County PUD #1	$ 720,554	1.5906%	1.5906%	$ 608,684	$ 608,690	$ 1,329,238	$ 1,329,244

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10239	Lincoln Elec Coop (MT)	$ -	0.1947%	0.1956%	$ 74,518	$ 74,845	$ 74,518	$ 74,845
10242	Lost River Elec Coop	$ 50,765	0.1370%	0.1372%	$ 52,418	$ 52,508	$ 103,183	$ 103,272
10244	Lower Valley Energy	$ -	1.2573%	1.2437%	$ 481,139	$ 475,963	$ 481,139	$ 475,963
10246	Mason County PUD #1	$ 52,092	0.1313%	0.1299%	$ 50,255	$ 49,714	$ 102,347	$ 101,807
10247	Mason County PUD #3	$ 544,117	1.1477%	1.1474%	$ 439,216	$ 439,105	$ 983,333	$ 983,222
10256	Midstate Elec Coop	$ 287,247	0.6681%	0.6691%	$ 255,685	$ 256,070	$ 542,932	$ 543,317
10258	Mission Valley	$ -	0.5151%	0.5219%	$ 197,135	$ 199,715	$ 197,135	$ 199,715
10259	Missoula Elec Coop	$ -	0.3819%	0.3845%	$ 146,140	$ 147,141	$ 146,140	$ 147,141
10260	Modern Elec Coop	$ -	0.3754%	0.3780%	$ 143,647	$ 144,654	$ 143,647	$ 144,654
10273	Nespelem Valley Elec Coop	$ 35,342	0.0859%	0.0850%	$ 32,888	$ 32,534	$ 68,230	$ 67,876
10278	Northern Lights	$ 134,905	0.5250%	0.5194%	$ 200,917	$ 198,755	$ 335,821	$ 333,660
10279	Northern Wasco County PUD	$ 169,186	0.8835%	0.8800%	$ 338,093	$ 336,749	$ 507,279	$ 505,935
10284	Ohop Mutual Light Company	$ -	0.1484%	0.1469%	$ 56,809	$ 56,198	$ 56,809	$ 56,198
10285	Okanogan County Elec Coop	$ 33,056	0.0954%	0.0944%	$ 36,507	$ 36,114	$ 69,563	$ 69,171
10286	Okanogan County PUD #1	$ 302,445	0.7109%	0.7076%	$ 272,062	$ 270,780	$ 574,507	$ 573,224
10288	Orcas P & L	$ -	0.3614%	0.3576%	$ 138,318	$ 136,830	$ 138,318	$ 136,830
10291	Oregon Trail Coop	$ 535,684	1.0682%	1.0742%	$ 408,793	$ 411,075	$ 944,477	$ 946,760
10294	Pacific County PUD #2	$ 263,432	0.4461%	0.5013%	$ 170,729	$ 191,859	$ 434,160	$ 455,291
10304	Parkland L & W	$ -	0.2019%	0.2020%	$ 77,281	$ 77,320	$ 77,281	$ 77,320
10306	Pend Oreille County PUD #1	$ 218,512	0.3035%	0.3434%	$ 116,147	$ 131,413	$ 334,658	$ 349,924
10307	Peninsula Light Company	$ 484,256	1.0248%	1.0333%	$ 392,174	$ 395,426	$ 876,430	$ 879,682
10326	U.S. Naval Base, Bremerton	$ 216,980	0.3926%	0.3884%	$ 150,228	$ 148,624	$ 367,208	$ 365,604
10331	Raft River Elec Coop	$ 81,677	0.4844%	0.4828%	$ 185,383	$ 184,750	$ 267,060	$ 266,427
10333	Ravalli County Elec Coop	$ -	0.2607%	0.2626%	$ 99,754	$ 100,499	$ 99,754	$ 100,499
10338	Riverside Elec Coop	$ -	0.0327%	0.0324%	$ 12,523	$ 12,404	$ 12,523	$ 12,404
10342	Salem Elec Coop	$ 342,469	0.5756%	0.5694%	$ 220,268	$ 217,898	$ 562,737	$ 560,367
10343	Salmon River Elec Coop	$ 126,695	0.4447%	0.4389%	$ 170,176	$ 167,979	$ 296,871	$ 294,674
10349	Seattle City Light	$ 2,806,762	7.6559%	7.5735%	$ 2,929,808	$ 2,898,290	$ 5,736,570	$ 5,705,052
10352	Skamania County PUD #1	$ 110,458	0.2271%	0.2273%	$ 86,921	$ 86,982	$ 197,380	$ 197,440
10354	Snohomish County PUD #1	$ 4,394,837	11.4873%	11.5471%	$ 4,396,048	$ 4,418,905	$ 8,790,886	$ 8,813,742
10360	Southside Elec Lines	$ -	0.0933%	0.0947%	$ 35,716	$ 36,232	$ 35,716	$ 36,232
10363	Springfield Utility Board	$ 490,736	1.4114%	1.4120%	$ 540,127	$ 540,355	$ 1,030,864	$ 1,031,092
10369	Surprise Valley Elec Coop	$ 81,780	0.2261%	0.2267%	$ 86,524	$ 86,765	$ 168,303	$ 168,545
10370	Tacoma Public Utilities	$ 2,979,021	5.7214%	5.7137%	$ 2,189,512	$ 2,186,556	$ 5,168,533	$ 5,165,577
10371	Tanner Elec Coop	$ 59,409	0.1612%	0.1595%	$ 61,696	$ 61,033	$ 121,106	$ 120,442
10376	Tillamook PUD #1	$ 287,525	0.7926%	0.7875%	$ 303,312	$ 301,382	$ 590,837	$ 588,908
10378	Coulee Dam, City of	$ -	0.0296%	0.0293%	$ 11,322	$ 11,200	$ 11,322	$ 11,200
10379	Steilacoom, Town of	$ 35,527	0.0696%	0.0695%	$ 26,637	$ 26,598	$ 62,164	$ 62,125

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10388	Umatilla Elec Coop	$ 557,880	1.6382%	1.6367%	$ 626,925	$ 626,353	$ 1,184,806	$ 1,184,234
10391	United Electric Coop	$ 144,156	0.4380%	0.4333%	$ 167,635	$ 165,831	$ 311,790	$ 309,987
10406	U.S. DOE Albany	$ 3,304	0.0066%	0.0065%	$ 2,533	$ 2,506	$ 5,838	$ 5,810
10408	U.S. Navy, Jim Creek	$ 10,783	0.0213%	0.0210%	$ 8,133	$ 8,045	$ 18,915	$ 18,828
10409	U.S. Navy, Bangor	$ 151,547	0.2896%	0.2869%	$ 110,810	$ 109,811	$ 262,357	$ 261,358
10426	U.S. DOE Richland	$ 193,387	0.3625%	0.3796%	$ 138,707	$ 145,268	$ 332,094	$ 338,655
10434	Vera Irrigation District	$ 190,495	0.3808%	0.3834%	$ 145,738	$ 146,732	$ 336,233	$ 337,226
10436	Vigilante Elec Coop	$ -	0.2642%	0.2661%	$ 101,091	$ 101,825	$ 101,091	$ 101,825
10440	Wahkiakum County PUD #1	$ 32,517	0.0726%	0.0724%	$ 27,794	$ 27,688	$ 60,311	$ 60,205
10442	Wasco Elec Coop	$ -	0.1958%	0.1937%	$ 74,915	$ 74,109	$ 74,915	$ 74,109
10446	Wells Rural Elec Coop	$ 388,509	1.3821%	1.3844%	$ 528,925	$ 529,808	$ 917,433	$ 918,317
10448	West Oregon Elec Coop	$ 48,959	0.1229%	0.1221%	$ 47,018	$ 46,717	$ 95,977	$ 95,676
10451	Whatcom County PUD #1	$ 179,980	0.3707%	0.3879%	$ 141,849	$ 148,439	$ 321,829	$ 328,419
10482	Umpqua Indian Utility Coop	$ 15,681	0.0477%	0.0510%	$ 18,269	$ 19,513	$ 33,950	$ 35,194
10502	Yakama Power	$ 7,897	0.0917%	0.0919%	$ 35,111	$ 35,186	$ 43,008	$ 43,083
10597	Hermiston, City of	$ 100,167	0.1812%	0.1801%	$ 69,332	$ 68,928	$ 169,498	$ 169,095
10706	Port of Seattle - SETAC	$ -	0.2408%	0.2390%	$ 92,167	$ 91,470	$ 92,167	$ 91,470
11680	Weiser, City of	$ -	0.0902%	0.0900%	$ 34,503	$ 34,423	$ 34,503	$ 34,423
Total		$ 38,269,000	100.0000%	100.0000%	$38,268,617	$38,268,617	$76,537,617	$76,537,617

(1) See Exhibit B of REP Settlement Agreement, Contract No. 11PB-12322. US BIA Wapato was annexed by Yakama Power; therefore the PF-02 Refund Amount is included under Yakama Power.

(2) Reflects adjustment to the Exhibit A Existing Resource amounts for Cowlitz PUD to reflect loss of Priest Rapids contract rights. Adjusted TOCAs are recomputed with Grant CHWM equal to 41.75 aMW, pursuant to Section 3.4 of the REP Settlement Agreement. Final Scaled TOCAs reallocate headroom (when customers' net requirement is below their RHWM allocated share of the Tier 1 System) among all customers pro rata to Adjusted TOCA percentages.

BONNEVILLE POWER ADMINISTRATION

DOE/BP-4326 July 2011