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

2007 Supplemental Wholesale Power Rate Case

ADMINISTRATOR'S FINAL RECORD OF DECISION

APPENDIX A

2007 WHOLESALE POWER RATE SCHEDULES (FY 2009) AND 2007 GENERAL RATE SCHEDULE PROVISIONS (FY 2009)

September 2008

WP-07-A-05A

(Conformed 1/30/09 to match errata corrections)

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BONNEVILLE POWER ADMINISTRATION
RATES
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ACRONYM LIST

AGC	Automatic Generation Control
aMW	Average Megawatt
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
C/M	Consumers/Mile of Line for Low Density Discount
COB	California-Oregon Border
CRC	Conservation Rate Credit
CSP	Customer System Peak
CY	Calendar Year (Jan-Dec)
DJ	Dow Jones
DSIs	Direct Service Industrial Customers
EN	Energy Northwest
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear)
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GTA	General Transfer Agreement
HLH	Heavy Load Hour
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
Mid-C	Mid-Columbia
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NERC	North American Electric Reliability Council

NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BIOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NR	New Resource Firm Power (rate)
NWPP	Northwest Power Pool
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
PF	Priority Firm Power (rate)
PNCA	Pacific Northwest Coordination Agreement
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
Project Act	Bonneville Project Act
REP	Residential Exchange Program
ROD	Record of Decision
RPSA	Residential Purchase and Sales Agreement
RTF	Regional Technical Forum
SCRA	Supplemental Contingency Reserve Adjustment
Slice	Slice of the System product
TAC	Targeted Adjustment Charge
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
USBR	U.S. Bureau of Reclamation
WECC	Western Electricity Coordinating Council
WSCC	Western Systems Coordinating Council
WSPP	Western Systems Power Pool

FINAL PROPOSAL FOR THE WP-07 SUPPLEMENTAL RATE CASE

2007 WHOLESALE POWER RATE SCHEDULES

(WP-07 Supplemental FY 2009)

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2007 POWER RATE SCHEDULES (FY 2009)
(WP-07 Supplemental)

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SCHEDULE PF-07R
PRIORITY FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest (PNW). Priority Firm (PF) Power may be purchased 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. Rates in this schedule are in effect beginning October 1, 2008, and apply to purchases under requirements' Firm Power sales contracts for a one-year period. The Slice Product is only available for public bodies and cooperatives who have signed Slice contracts for the FY 2002-2011 period. Utilities participating in the Residential Exchange Program (REP) under Section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the one-year rates listed in this rate schedule in addition to applicable transmission charges.

This rate schedule supersedes the PF-07 rate schedule, which went into effect October 1, 2006. Sales under the PF-07R rate schedule are subject to BPA's 2007 General Rate Schedule Provisions (FY 2009) (2007 Supplemental GRSPs). Products available under this rate schedule are defined in BPA's 2007 Supplemental GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2007 Supplemental GRSPs and billing process.

For ease of reference, BPA uses the term PF rate and PF Preference rate interchangeably.

SECTION II. RATE TABLES

The rates in this section apply to PF products as shown in Section IV. The PF Exchange rate is shown in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2009

1.1 Applicability

These monthly rates apply for the rate period for customers purchasing Firm Power. These monthly rates are also used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable Months	***Rate***
January	$1.82 $/kW-mo
February	$1.85 $/kW-mo
March	$1.72 $/kW-mo
April	$1.62 $/kW-mo
May	$1.34 $/kW-mo
June	$1.23 $/kW-mo
July	$1.50 $/kW-mo
August	$1.76 $/kW-mo
September	$1.82 $/kW-mo
October	$1.91 $/kW-mo
November	$2.04 $/kW-mo
December	$2.14 $/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2009

1.1 Applicability

These rates apply for the rate period for customers purchasing Priority Firm Power. These rates are used to implement the Pre-Subscription Contracts.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	27.60 mills/kWh	19.96 mills/kWh
February	28.19 mills/kWh	20.16 mills/kWh
March	26.15 mills/kWh	19.17 mills/kWh
April	24.54 mills/kWh	17.64 mills/kWh
May	20.50 mills/kWh	14.17 mills/kWh
June	18.55 mills/kWh	9.85 mills/kWh
July	22.85 mills/kWh	16.73 mills/kWh
August	26.76 mills/kWh	19.85 mills/kWh
September	27.62 mills/kWh	22.17 mills/kWh
October	29.21 mills/kWh	21.40 mills/kWh
November	31.15 mills/kWh	22.72 mills/kWh
December	32.51 mills/kWh	23.85 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2009 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.46 mill/kWh.

D. SLICE RATE

1. Applicability

This rate applies to customers purchasing the Slice Product. This rate will remain constant during the rate period.

2. Rate

The monthly rate for the Slice Product is $1,872,639 per 1 percent of Slice.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to sales under the Residential Exchange Program.

A. ENERGY RATE

1. PF Exchange Energy Rates for FY 2009

1.1 Applicability

These rates apply to utilities purchasing exchange power under the Residential Exchange Program.

1.2 Base PF Exchange Rate

The Base PF Exchange rate applies to utilities purchasing exchange power and is subject to a Utility Supplemental 7(b)(3) Rate Charge, which is established specifically for each respective utility. The Base PF Exchange rate is 38.74 mills/kWh.

1.3 Supplemental 7(b)(3) Rate Charge and PF Exchange Rate Table

	2009 Utility Supplemental 7(b)(3) Rate Charge	Utility PF Exchange Rates
Avista	6.22 mills/kWh	44.96 mills/kWh
Idaho Power	0.00 mills/kWh	38.74 mills/kWh
Northwestern Energy	8.68 mills/kWh	47.42 mills/kWh
PacifiCorp	6.76 mills/kWh	45.50 mills/kWh
Portland General	9.10 mills/kWh	47.84 mills/kWh
Puget Sound Energy	11.31 mills/kWh	50.05 mills/kWh
Centralia	0.00 mills/kWh	38.74 mills/kWh
Franklin	3.77 mills/kWh	42.51 mills/kWh
Snohomish County PUD No. 1	0.00 mills/kWh	38.74 mills/kWh

1.4 Supplemental Charge for Non-Listed Utilities

For eligible customers not listed in the Supplemental Rate Table, the applicable Supplemental Charge will equal the customer’s Average System Cost minus the Base PF Exchange rate. The customer’s Average System Cost will be determined pursuant to BPA’s Average System Cost Methodology.

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SECTION IV. PRODUCT LIST

The rates described above apply to the following products.

Section IV.A. Full Service Product

Section IV.B. Actual Partial Service Product – Simple

Section IV.C. Actual Partial Service Product – Complex

Section IV.D. Block Product

Section IV.E. Block Product with Factoring

Section IV.F. Block Product with Shaping Capacity

Section IV.G. Slice Product

Section IV.H. PF Exchange Power

A. FULL SERVICE PRODUCT

Purchases of the Core Subscription Full Service Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Measured Demand on the monthly Generation System Peak (GSP)
as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

B. ACTUAL PARTIAL SERVICE PRODUCT – SIMPLE

Purchases of the Core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

C. ACTUAL PARTIAL SERVICE PRODUCT – COMPLEX

Purchases of the Core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

D. BLOCK PRODUCT

Purchases of the Core Subscription Block Product are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PF) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

E. BLOCK PRODUCT WITH FACTORING

Purchases of the Core Subscription Block Product with Factoring are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible Priority Firm Power (PF) Rate Option	II.J
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

F. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the Core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. Priority Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement
as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible Priority Firm Power (PF) Rate Option	II.J
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to Public Preference Customers and are subject to the charges specified below.

1. Slice Product Charge

The charge for the Slice Product will be:
the elected Slice Percentage expressed as a decimal (.01 = 1%)
multiplied by
100
multiplied by
the Slice Rate in Section II.D.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Low Density Discount	II.L
Slice True-Up Adjustment	II.N
Unauthorized Increase Charge	II.Q

H. PRIORITY FIRM EXCHANGE POWER

This PF Exchange rate applies to sales under the Residential Exchange Program.

1. Priority Firm Exchange Power Charges

1.1 Demand Charge

No separate charge for demand.

1.2 Energy Charge

The monthly charge for energy will be:
the Purchaser's Billing Energy (which is the energy associated with
the utility's qualifying residential and small farm load for each billing period as determined by BPA in accordance with the provisions of the Purchaser's RPSA)
multiplied by
the Base PF Exchange rate modified by a Utility Supplemental 7(b)(3) Rate Charge established specifically for each respective utility. See Section III.A.1.2.

1.3 Load Variance Charge

No additional charge.

2. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services at a rate based on the Network Transmission (NT) rate schedule or its successor. The Base PF Exchange rate in the Section III.A.1.2 Rate Table includes the transmission charge.

Customers purchasing under this rate schedule are charged for Load Regulation based on the applicable charge established by Transmission Services (TS) or its successor. The Base PF Exchange rate in the Section III.A.1.2 Rate Table includes the charge for load regulation.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Low Density Discount	II.L
Supplemental 7(b)(3) Rate Charge Adjustment	II.S

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.

SCHEDULE NR-07R
NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the PNW. New Resource Firm Power (NR) is available to IOUs under net requirements contracts for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service. NR also is available to any public body, cooperative, or Federal agency to the extent such power is needed to serve any New Large Single Load (NLSL), as defined by the Northwest Power Act. That portion of the utility's load placed on BPA that is attributable to the NLSL will be billed under this rate schedule.

Rates in this schedule apply from October 1, 2008, through September 30, 2009, for purchasers of New Resource Firm Power. Products available under this rate schedule are defined in BPA's 2007 Supplemental General Rate Schedule Provisions (FY 2009) (2007 Supplemental GRSPs).

This rate schedule supersedes the NR-07 rate schedule, which went into effect October 1, 2006. Sales under the NR-07R rate schedule are subject to BPA's 2007 Supplemental GRSPs and billing process.

SECTION II. RATE TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2009

1.1 Applicability

These rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	***Rate***
January	$1.82 $/kW-mo
February	$1.85 $/kW-mo
March	$1.72 $/kW-mo
April	$1.62 $/kW-mo
May	$1.34 $/kW-mo
June	$1.23 $/kW-mo
July	$1.50 $/kW-mo
August	$1.76 $/kW-mo
September	$1.82 $/kW-mo
October	$1.91 $/kW-mo
November	$2.04 $/kW-mo
December	$2.14 $/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2009

1.1 Applicability

These rates apply to eligible customers purchasing power under this rate schedule.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	70.21 mills/kWh	48.35 mills/kWh
February	71.90 mills/kWh	48.92 mills/kWh
March	66.05 mills/kWh	46.07 mills/kWh
April	61.45 mills/kWh	41.69 mills/kWh
May	49.88 mills/kWh	31.76 mills/kWh
June	44.31 mills/kWh	19.40 mills/kWh
July	56.62 mills/kWh	39.09 mills/kWh
August	67.81 mills/kWh	48.03 mills/kWh
September	70.29 mills/kWh	54.66 mills/kWh
October	74.82 mills/kWh	52.46 mills/kWh
November	80.39 mills/kWh	56.25 mills/kWh
December	84.28 mills/kWh	59.49 mills/kWh

1.3 Section 7(b)(3) Supplemental Rate Charge

A Supplemental rate charge of 8.80 mills/kWh shall be added to each NR energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.46 mill/kWh.

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SECTION III. BILLING FACTORS, AND ADJUSTMENTS FOR EACH NR PRODUCT

This rate schedule contains seven subsections, corresponding to the products to which this rate schedule applies. The following seven products are available to serve NLSLs, or other loads served at the NR-07R rate.

Section III.A. New Large Single Load

Section III.B. Full Service Product

Section III.C. Actual Partial Service Product – Simple

Section III.D. Actual Partial Service Product – Complex

Section III.E. Block Product

Section III.F. Block Product with Factoring

Section III.G. Block Product with Shaping Capacity

A. NEW LARGE SINGLE LOAD (NLSL) SERVICE PRODUCT

Purchases of New Resource Firm Power to serve an NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the NLSL's monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

(1) The NLSL's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) the NLSL's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the NLSL's Measured Energy for the billing period as specified in the contract
multiplied by
the Load Variance Rate from Section II.C.

If the customer is already paying the Load Variance Charge on the NLSL load through this or another rate schedule, this charge does not apply.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

B. FULL SERVICE PRODUCT

Purchases of the Core Subscription Full Service Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Measured Demand on the GSP as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

C. ACTUAL PARTIAL SERVICE PRODUCT - SIMPLE

Purchases of the Core Subscription Actual Partial Service Product – Simple are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

D. ACTUAL PARTIAL SERVICE PRODUCT – COMPLEX

Purchases of the Core Subscription Actual Partial Service Product – Complex are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be:
the Purchaser's Total Retail Load for the billing period
multiplied by
the Load Variance Rate from Section II.C.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

E. BLOCK PRODUCT

Purchases of the Core Subscription Block Product are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as
specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

F. BLOCK PRODUCT WITH FACTORING

Purchases of the Core Subscription Block Product with Factoring are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
a Demand Adjuster
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Excess Factoring Charges	II.H
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

G. BLOCK PRODUCT WITH SHAPING CAPACITY

Purchases of the Core Subscription Block Product with Shaping Capacity are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser's HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Conservation Surcharge	II.B
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Flexible New Resource Firm Power (NR) Rate Option	II.I
Green Energy Premium	II.K
Low Density Discount	II.L
Rate Melding	II.M
Targeted Adjustment Charge	II.P
Unauthorized Increase Charge	II.Q

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Services and the customer negotiate otherwise at time of sale. Regulation and Frequency Response may have to be purchased for NLSLs.

IP-07R
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct service industrial customers (DSIs) for Firm Power to be used in their industrial operations. DSIs that are offered a requirements contract for which power deliveries begin on or after October 1, 2008, are eligible to purchase under this rate schedule.

This rate schedule supersedes the IP-07 rate schedule, which went into effect October 1, 2006. Sales under the IP-07R rate schedule are subject to BPA's 2007 Supplemental General Rate Schedule Provisions (FY 2009) (2007 Supplemental GRSPs) and billing process.

SECTION II. RATE TABLES

The rates for the Industrial Firm Power (IP) product are identified below.

A. DEMAND RATE FOR ALL IP PRODUCTS

1. Monthly Demand Rate for FY 2009

1.1 Applicability

These monthly rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	***Rate***
January	$1.82 $/kW-mo
February	$1.85 $/kW-mo
March	$1.72 $/kW-mo
April	$1.62 $/kW-mo
May	$1.34 $/kW-mo
June	$1.23 $/kW-mo
July	$1.50 $/kW-mo
August	$1.76 $/kW-mo
September	$1.82 $/kW-mo
October	$1.91 $/kW-mo
November	$2.04 $/kW-mo
December	$2.14 $/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2009

1.1 Applicability

These energy rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	30.00 mills/kWh	19.26 mills/kWh
February	30.83 mills/kWh	19.54 mills/kWh
March	27.96 mills/kWh	18.15 mills/kWh
April	25.70 mills/kWh	15.99 mills/kWh
May	20.02 mills/kWh	11.12 mills/kWh
June	17.28 mills/kWh	5.05 mills/kWh
July	23.33 mills/kWh	14.72 mills/kWh
August	28.82 mills/kWh	19.11 mills/kWh
September	30.04 mills/kWh	22.36 mills/kWh
October	32.26 mills/kWh	21.28 mills/kWh
November	35.00 mills/kWh	23.14 mills/kWh
December	36.91 mills/kWh	24.74 mills/kWh

1.3 Section 7(b)(3) Supplemental Rate Charge

A Supplemental rate charge of 8.80 mills/kWh shall be added to each IP energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.46 mill/kWh.

SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR THE IP PRODUCT

Only the firm take-or-pay Block Product is available under this rate schedule. Energy charges for the IP product would apply as specified in Section II.B.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser’s monthly Demand Entitlement as specified in the contract
multiplied by
the monthly Demand Rate from Section II.A.

1.2 Energy Charge

The total monthly charge for energy will be the sum of (1) and (2):

(1) The Purchaser’s HLH Energy Entitlement as specified in the contract
multiplied by
the monthly HLH Energy Rate from Section II.B.

(2) The Purchaser’s LLH Energy Entitlement as specified in the contract
multiplied by
the monthly LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

Not applicable to Block purchases unless the customer is also purchasing another product to which Load Variance is applicable as specified by contract.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below:

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Conservation Rate Credit	II.A
Cost Contributions	II.C
Cost Recovery Adjustment Clause	II.D
Dividend Distribution Clause	II.F
Emergency NFB Surcharge	II.G
Green Energy Premium	II.K
Supplemental Contingency Reserves Adjustment	II.O
Unauthorized Increase Charge	II.Q

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's Power Services and the customer negotiate otherwise at time of sale.

SCHEDULE FPS-07R
FIRM POWER PRODUCTS AND SERVICES

SECTION I. 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, and Reassignment or Remarketing of Surplus Transmission Capacity for use inside and outside the Pacific Northwest during the period beginning October 1, 2008, and ending September 30, 2009.

Products and services available under this rate schedule are described in 2007 Supplemental General Rate Schedule Provisions (FY 2009) (2007 Supplemental GRSPs). BPA is not obligated to sell even if sales will not displace PF/NR/IP sales. Sales under the FPS-07R rate schedule are subject to the applicable provisions of BPA's 2007 Supplemental GRSPs. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged under the applicable transmission rate schedule.

This rate schedule supersedes the Firm Power Products and Services (FPS-07) rate schedule. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2007 Supplemental GRSPs and billing process.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

For each product, the rate(s) for each product, along with the associated billing factor(s), are identified below. Applicable adjustments, charges, and special rate provisions are listed for each product. This rate schedule contains five subsections, corresponding to the products offered under this rate schedule:

Section II.A. Firm Power and Capacity Without Energy

Section II.B. Supplemental Control Area Services

Section II.C. Shaping Services

Section II.D. Reservation and Rights to Change Services

Section II.E. Reassignment or Remarketing of Surplus Transmission Capacity

A. FIRM POWER AND CAPACITY WITHOUT ENERGY

1. Flexible Rate

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

2. Supplemental 7(b)(3) Rate Charge

A Supplemental Rate Charge of 8.80 mills/kWh shall be included in each FPS energy rate charge as determined pursuant to paragraph A.1 above. The inclusion of this Supplemental rate charge shall not inhibit the energy rate charge of the Flexible Rate from being either positive or negative. The total rate charge shall equal the sum of (1) the energy rate charge specified by BPA or as mutually agreed by BPA and the purchaser, and (2) the Supplemental rate charge. BPA will show only the total rate charge on the customer bill and contract or confirm.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the Supplemental 2007 GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q
West-Wide Price Cap of FPS Sales	II.R

B. SUPPLEMENTAL CONTROL AREA SERVICES

1. Rates and Billing Factors

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

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

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q

C. SHAPING SERVICES

1. Rates and Billing Factors

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

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

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2007 Supplemental GRSPs. Relevant sections are identified below.

Adjustments, Charges, and Special Rate Provisions	***2007 GRSPs Section***
Cost Contributions	II.C
Unauthorized Increase Charge	II.Q

D. RESERVATION AND RIGHTS TO CHANGE SERVICES

1. Rates and Billing Factors

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

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

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.

E. 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).

1. Rates and Billing Factors

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

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

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.

GENERAL TRANSFER AGREEMENT (GTA) DELIVERY CHARGE

Customers who purchase Federal power that is delivered over non-Federal low-voltage transmission facilities shall pay a 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) and other non-Federal transmission service agreements.

1. Rate

$1.119 per kilowatt per month

2. Billing Factor

The monthly Billing Factor for the GTA Delivery rate shall be the total amount of Federal power delivered 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 agreements.

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 Factor 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 and metered flow into BPA's Control Area.

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2007 GENERAL RATE SCHEDULE PROVISIONS

(GRSPs) FOR POWER RATES

(WP-07 SUPPLEMENTAL FY 2009)

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2007 GENERAL RATE SCHEDULE PROVISIONS

Subject **Page**

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2007 GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

These 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009) (2007 Supplemental GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). BPA has requested that FERC make these rates and 2007 Supplemental GRSPs effective on October 1, 2008. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These Wholesale Power Rate Schedules (FY 2009) and the 2007 Supplemental GRSPs associated with these schedules supersede BPA's 2007 rate schedules (that became effective October 1, 2006) to the extent stated in the Availability Section of each rate schedule, and the FPS-07 that became effective October 1, 2006. These schedules and the 2007 Supplemental GRSPs shall be applicable to all BPA contracts, including contracts executed both 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).

These 2007 rate schedules do not supersede any previously established rate schedule which 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. A late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the applicable "Prime Rate" (reported in the "Money Rates" Section of the Wall Street Journal) plus 4 percent; by 365. 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 GRSPs administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation Rate Credit (CRC)

1. Purpose and General Overview of the of the Conservation Rate Credit

(a) The Conservation Rate Credit (CRC) is available to customers purchasing under the PF (except PF Exchange), IP, and NR rate schedules that take action to achieve cost-effective conservation and renewable resource development in the region.

(b) Each customer will be eligible for the CRC rate credit, set at 0.5 mills/kWh, applied to their eligible loads. The CRC rate credit is included in the posted rates for Subscription power purchases.

(c) Individual participants in the CRC rate credit will make investments in cost-effective conservation and qualifying renewable resource development in the region, in a dollar amount equal to their eligible BPA loads times 0.5 mills/kWh.

(d) BPA will determine and publish lists of eligible measures and specific activities in the most current CRC Implementation Manual that satisfy customer obligations when implemented.

(e) Published lists will include the specific dollar amount of eligibility credited for each qualifying measure or activity.

(f) Each customer participating in the CRC program will administer its CRC activities pursuant to the most current CRC Implementation Manual.

2. Calculation of the Conservation Rate Credit

(a) Applicable Rate Schedules and Contracts. The CRC rate credit applies to loads served under the following:

(1) Priority Firm Power (PF-07R) rate schedule (excluding the PF Exchange rate).

(2) Slice product under the PF-07R rate schedule

(3) New Resource Firm Power (NR-07R) rate schedule.

(4) Industrial Firm (IP-07R) rate schedule.

(b) Sources of CRC Qualifying Load Data

(1) Qualifying loads for customers purchasing Full, Partial Requirements, or Block Subscription products will be equal to the total of their respective annual forecast average net requirements established in the July 2006 Load Resource Study and Documentation, WP-07-FS-BPA-01A, Chapters 2.2.1 and 2.2.2.

(2) Loads for individual Slice customer will be calculated using their individual slice percentage times 7070 aMW.

(c) Calculation of the Monthly and Annual CRC Eligibility

(1) For Full and Partial Requirements, Block, and Slice customers, BPA determines each customer's average monthly load by dividing the total forecast load for the three-year 2007 through 2009 rate period determined in section 2 (b) by 36. Then BPA will multiply each customer's average monthly load by 0.5 mills/kWh (*i.e.*, $0.0005) and round to the nearest whole dollar. This number is equal to the customer's rounded monthly rate credit.

(2) The customer's annual CRC eligibility will be determined by multiplying the rounded monthly CRC by 12.

(d) Applications of the Monthly Rate Credit

(1) The monthly rate credit will be posted, as a deduction, on the customer's monthly total power bill.

(2) The monthly rate credit will be subtracted after BPA has determined all other charges and credits on the participating customer's power bill.

(3) BPA will provide the monthly rate credit even in those months when the amount is larger than the customer's total power bill amount.

(4) For customers showing an annual net billing capacity deficiency, BPA may disburse the customer's monthly rate credit in the form of a monthly check in the same amount as the customer's monthly CRC.

(e) Notification.

(1) Prior to the beginning of the early start of the CRC (January 1, 2006), the BPA Power Business Line Customer Account Executives will send each participating customer a letter documenting the forecast qualifying loads and monthly rate credit amounts for the duration of the FY 2007-2009 Rate Period.

3. Reporting and Review of Individual Customers' CRC Activity

(a) Customers submitting progress reports documenting cumulative qualifying expenditures of less than 50 percent of the cumulative monthly rate credits after the second semi-annual report (*i.e.*, October 31, 2007) must prepare an action plan documenting planned spending for the remainder of the rate period that shows how they will increase their CRC activities to acceptable levels.

(b) Customers submitting progress reports documenting cumulative qualifying expenditures of less than 75 percent of the cumulative monthly rate credits after the third semi-annual report (*i.e.*, April 30, 2008) may become ineligible to receive the CRC rate credit. If determined ineligible, BPA will suspend the customer's CRC rate credit on their power bill for the remainder of the rate period.

(1) BPA will provide the customer notice of removal of the CRC monthly rate credit from the customer's bill no later than June 30, 2008.

(2) BPA will remove the CRC monthly rate credit from the customer's bill for the first billing period beginning 61 calendar days or more from the date of the BPA notice of removal.

(3) Customer eligibility for the CRC will end on the last day of the first billing period ending 60 calendar days or more BPA provides a customer notice of removal of the CRC monthly rate credit.

(4) Customers ineligible to receive the CRC will be required to report to the BPA CRC manager total CRC qualifying expenditures within 90 calendar days of receiving notice from BPA determining their ineligibility.

(A) If total reported CRC qualifying expenditures are less than total accumulated monthly rate credits, computed from the beginning of the rate period to the last day of customer eligibility, the customer will be required to:

i. report additional qualifying expenditures within 120 calendar days of receiving a notice of ineligibility;

OR

ii. reimburse BPA for the difference between total reported qualifying expenditures and total accumulated monthly rate credits within 120 calendar days of receiving a notice of ineligibility.

(c) Customers may elect not to receive the CRC monthly rate credit by giving BPA 60 calendar days' written notice of their intent to stop participation.

(1) BPA will remove the CRC monthly rate credit from a customer's bill for the first billing period beginning 61 calendar days or more after BPA receipt of the customer's notice.

(2) Customer eligibility for the CRC monthly rate credit will end on the last day of the billing period ending 60 calendar days or more after BPA receipt of the customer's notice.

(3) Customers electing not to receive the CRC monthly rate credit will be required to report to BPA total CRC qualifying expenditures within 90 calendar days of BPA receipt of the customers' notice.

(A) If total reported CRC qualifying expenditures are less than total accumulated monthly rate credits, computed from the beginning of the rate period to the end of customer eligibility, the customer will be required to:

i. report additional qualifying expenditures within 120 calendar days of BPA receipt of customer's notice.

OR

ii. reimburse BPA for the difference between total reported qualifying expenditures and total accumulated monthly rate credits, within 120 calendar days of BPA receipt of customer's notice.

(d) Final Reconciliation Reports

(1) Within 30 calendar days of the end of the rate period (October 31, 2009), each customer shall submit a final reconciliation report summarizing the customer's total CRC qualifying expenditures and total CRC accumulated monthly rate credits for the rate period to the BPA CRC manager for review.

(2) If a participating customer's final reconciliation report shows that the total CRC accumulated monthly rate credit received from BPA exceeds the customer's total CRC qualifying expenditures, the customer may take an additional month (for a total of two months after the end of the rate period) to make the necessary additional qualifying expenditures and prepare a revised final reconciliation report.

(3) The final report is due to BPA within two months of the end of the rate period (December 1, 2009). If the customer's total CRC qualifying expenditures still do not equal or exceed their total CRC accumulated monthly rate credit, the customer must reimburse the difference to BPA on or before January 31, 2010.

(4) No reimbursements are required of any participating customer whose total CRC qualifying expenditures over the rate period are equal to or exceed the total CRC accumulated monthly rate credit received from BPA.

(5) BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2009) shall be subject to a late payment charge as described in the customer's Subscription contract.

B. Conservation Surcharge

The Conservation Surcharge, where 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 would apply to PF-07R (including Slice purchasers) and NR-07R rate schedules.

C. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecast average cost of resources available to BPA under average water conditions is 33.97 mills/kWh.

2. The approximate cost contribution of different resource categories to each rate schedule is as shown in Table A:

Table A

Rate Schedule	***Resource Cost Contribution***		
	Federal Base System	**Exchange**	**New Resources**
PF	54.04%	45.96%	0%
IP	0%	72.56%	27.44%
NR	0%	72.56%	27.44%
FPS	0%	72.56%	27.44%

D. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to the FY 2009 energy base rates published in the Record of Decision (ROD) for the WP-07 rate case. *See* WP-07-A-05, Administrator's Final ROD, Appendix A. The amount of incremental net revenue to be collected is calculated by subtracting Power Services' Accumulated Modified Net Revenues (AMNR) (as defined in this GRSP under "Calculations for the CRAC") from the annual Threshold. If this amount is negative, there is no CRAC; if this amount is positive, a CRAC will be implemented to collect the lesser of this amount and the CRAC cap.

The CRAC applies to Light Load Hours (LLH) Energy and Heavy Load Hours (HLH) Energy and Load Variance sales under these firm power rate schedules:
- PF-07R [Preference (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The CRAC does not apply to:
- sales under the PF Slice Product; or
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts; or
- Demand Sales (However, if a trigger event under the NFB Adjustment increases the CRAC cap, and the CRAC triggers for an amount greater than the original cap, the amount of CRAC revenue in excess of the original cap will be collected through an increase to all Demand, Energy, and Load Variance Rates proportionately); or
- DSI financial benefits.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of FY 2009, BPA will forecast the FY 2008 end-of-year AMNR. If the forecast AMNR is less than the CRAC Threshold for that fiscal year, the CRAC will trigger, and a rate increase will go into effect beginning on October 1, 2008.

(a) Calculating the CRAC Amount

CRAC Amount is the lower of:

CRAC Threshold minus forecast AMNR;

or

The Maximum CRAC Recovery Amount (Cap), shown in Table B below.

Table B: CRAC Annual Thresholds and Caps
[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	**CRAC Applied to Fiscal Year**	**CRAC Threshold Measured in AMNR**	**Approx. Threshold as Measured in Power Services Reserves**	**Maximum CRAC Recovery Amount (Cap)***
2008	2009	($29.3)	$750	$36

* The Maximum CRAC Recovery Amount (Cap) may be modified to account for adjustments made to the Cap by the NFB Adjustment (if triggered) calculated at the end of FY 2008.

Where CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate in FY 2009.

Where CRAC Threshold is the “trigger point” for invoking a rate increase under the CRAC. The CRAC Threshold is specified for the end of FY 2008, in Table B.

Where AMNR is generation function net revenues, as accumulated since 1999, at the end of FY 2008. The forecast of AMNR is used to determine if the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of AMNR will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the period.

Where MNR for FY 2008 is defined as generation function accrued revenues less accrued expenses (in accordance with Generally Accepted Accounting Principles), with three exceptions:

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative

Instruments and Hedging Activities (including Supplemental standards issued by FASB and interpretations regarding derivatives and hedging activities), and actual Energy Northwest (EN) debt service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives Implementation Group issues (together, "FAS 133")* as of October 1, 2000.)

(2) The calculation of MNR will include forecast EN debt service identified in the WP-07 Final Supplemental Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecast results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecast revenues, positive or negative, from contractual true-ups pursuant to the Slice Agreement.

<u>Where Maximum CRAC Recovery Amount (Cap)</u> is the maximum annual amount that is allowed to be recovered through the CRAC.

(b) Converting the CRAC Amount to a Percentage

Once the CRAC Amount is determined, that amount will be converted to the CRAC Percentage. The CRAC Percentage is the percentage increase applied to customers' HLH and LLH Energy and Load Variance rates under the firm power rate schedules subject to the CRAC. The additional CRAC revenue will be generated by applying this percentage to the applicable power rates and benefits in the following way:

(1) The CRAC Percentage is calculated by dividing the CRAC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the CRAC.

(2) For products subject to the CRAC, the CRAC percentage will be applied to HLH and LLH base energy rates and the Load Variance rate for the twelve months beginning in October and ending the following September.

2. Actions to Mitigate the CRAC

If Power Services' accumulated modified net revenues at the end of a fiscal year are within $150 million of the CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for the causes of BPA's financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. BPA shall conduct a comment period on these actions to avert or reduce a potential CRAC rate adjustment by the following October.

3. CRAC Adjustment Timing

In early October 2008, the Administrator will determine whether the expected value of the AMNR forecast at the end of FY 2008 is below the CRAC Threshold. If the AMNR is forecast to fall below the CRAC Threshold, the Administrator will propose, by early October, to assess a cost recovery adjustment to applicable rates for power deliveries beginning in October 2008 (FY 2009).

Customers will be notified, on or about mid-October, of the percentage increase applicable to the base, if any, due to the CRAC. The rates used to calculate the customers' bills for FY 2009 will reflect the CRAC increase.

(a) CRAC Notification Process

BPA shall follow the following 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 AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external web site (www.bpa.gov) the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notice of CRAC Trigger

BPA shall complete a forecast of current fiscal end-of-year AMNR in late September 2008. BPA shall notify all customers and rate case parties by early October 2008 if the expected value of the AMNR forecast falls below the CRAC Threshold for the CRAC applicable to FY 2009, and, if so, by mid-October the extent to which BPA intends to adjust rates due to the CRAC. Notification will be posted on BPA's web site and will include the audited

AMNR for FY 2007, the forecast of end-of-year FY 2008 AMNR, the calculation of the Revenue Amount, and the FY 2009 CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA for the AMNR determination. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

If the FY 2008 AMNR is forecast to fall below the CRAC Threshold, BPA staff shall conduct a workshop(s) in mid-October 2008 to explain the AMNR forecast, the calculation of the CRAC Amount and the CRAC Percentage, and to demonstrate that the CRAC has been implemented in accordance with these GRSPs. The workshop will provide an opportunity for public comment.

The Administrator may elect at his discretion to reduce the CRAC rate adjustment as long as the resulting one-year TPP (for FY 2009) is greater than or equal to 97.5 percent. If the Administrator so elects, he shall inform the customers of his decision during the workshop.

If the FY 2008 AMNR is forecast to fall below the CRAC Threshold, BPA will post to the BPA web site the final calculation of the percentage adjustment to each product and the dollar adjustment to each benefit subject to the CRAC as described above no later than October 31, 2008. This will include any NFB Adjustment (see below) to the CRAC calculation.

4. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the CRAC Cap for FY 2009 if financial impacts from a specified set of circumstances in the fish and wildlife arena cause a net reduction in net revenue. The NFB Adjustment calculation results in an increase in the annual CRAC maximum recovery amount defined in Table B for FY 2009 if an NFB Trigger Event occurs in FY 2008. The NFB Adjustment is applicable to FY 2009.

CRAC Amounts in excess of the amounts recoverable under the Maximum CRAC Recovery Amount (Cap) as shown in Table B will be proportionally collected from LLH and HLH Energy, Load Variance, and Demand sales under the firm power rate schedules subject to the CRAC.

(a) Triggering the NFB Adjustment

An NFB Trigger Event is one of the following four kinds of events that results in changes to BPA's FCRPS ESA obligations compared to those in the WP-07 Final Supplemental Proposal 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 a NMFS-issued FCRPS BiOp, 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 NMFS FCRPS BiOp; or

(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.

(b) Formula for Calculating the NFB Adjustment

The calculation will compare the financial results of the program spending and modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed, to the financial results of the modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes (or court-approved, etc.).

The NFB Adjustment calculation will be determined by the following formula:

NFB Adjustment = the minimum of $0 and

(Expected Net Revenue Before Financial Impacts

Minus

Expected Net Revenue After Financial Impacts)

<u>Where the NFB Adjustment</u> is the reduction in generation function modified net revenues (if any) from before the change to after the change in the program spending and modeled operations of the power system.

<u>Where the Expected Net Revenue Before Financial Impacts</u> is based on the program spending and modeled operation of the power system under the total set of fish and wildlife mitigation measures actually employed for the current fiscal year, net of estimated 4(h)(10)(C) credits and the Slice True-Up.

Where the Expected Net Revenue After Financial Impacts is based on the program spending and modeled operation of the power system under the same set of fish and wildlife mitigation measures except with the removal of the court-ordered changes for the current fiscal year, net of estimated 4(h)(10)(C) credits and the Slice True-Up.

The adjustment to the CRAC Cap will be determined by the following formula:

Modified CRAC Cap =

CRAC Cap

Plus

NFB Adjustment

Where the Modified CRAC Cap is the CRAC Cap after the NFB Adjustment.

Where the Cap is the maximum annual amount allowed to be recovered at the beginning of the FY 2009 rate period specified in the GRSPs (*see* Table B).

(c) NFB Adjustment Timing

In October of FY 2009, BPA will determine the financial impacts, if any, of any NFB Trigger Events (*see* Section D.4.(a) above) that occurred in FY 2008. If the financial impacts from Trigger Events have reduced BPA's anticipated net revenue for FY 2008, BPA will propose around late October 2008 the increase to the CRAC Cap for FY 2009.

(d) NFB Notification Process

BPA will notify customers within 30 days of the occurrence of an NFB Trigger Event, as defined above, if BPA estimates the financial impact of the Trigger Event to be greater than $10 million. This initial notification, posted to BPA's web site, will include a description of the event. If BPA estimates the financial impact of a trigger event to be less than $10 million, BPA may not notify customers of the trigger event. In either case, however, the financial impact of the event will be presented with the forecast of the end-of-year AMNR calculation in October 2008. There can be more than one NFB Adjustment trigger event in FY 2008. There will only be one, if any, calculation of the NFB Adjustment amount applicable to FY 2009.

No later than October 31, 2008, BPA will notify customers of the calculated final CRAC percentage. Any NFB Adjustment will be included in this final notification.

E. Demand Adjuster

The Demand Adjuster is applied to a customer's demand billing factor. It is a number less than or equal to one calculated by dividing the customer's Total Retail Load on the GSP by the customer's Total Retail Load on their system peak. The minimum Demand Adjuster is 0.6 (six tenths). The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

F. Dividend Distribution Clause

The DDC is a rate adjustment establishing criteria for the distribution of funds to customers. The DDC enables BPA to distribute funds to eligible firm power customers and establishes the mechanism to be used to make a distribution. The amount of the distribution is calculated by subtracting the DDC Threshold in Table D from Power Services' Accumulated Modified Net Revenues (AMNR) (as defined by the DDC). If the resulting amount is negative, there is no DDC; if it is positive, a DDC in that amount will be implemented during FY 2009.

The DDC applies to LLH and HLH Energy and Load Variance rates subject to these firm power rate schedules:

- PF-07R [Preference (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R);
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The DDC does not apply to:

- sales under the PF Slice Product;
- power sales under Pre-Subscription contracts to the extent prohibited by such contracts;
- Demand Sales;
- DSI financial benefits.

1. Calculations for the Dividend Distribution Clause

In October 2008, BPA will forecast the FY 2008 end-of-year AMNR. If the forecast AMNR is greater than the defined DDC Threshold for that fiscal year, the DDC will trigger, and a rate reduction will go into effect beginning in October of FY 2009.

(a) Calculating the DDC Amount

DDC Amount =

Forecast AMNR

minus

DDC Threshold, shown in Table D below.

Table D: DDC Thresholds
[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold Measured in AMNR	Approx. Threshold as Measured in Power Services Reserves
2008	2009	$270.7	$1,050

Where DDC Amount is the reduction in modified net revenues that a decrease in rates, due to the DDC, is intended to generate in the next fiscal year.

Where DDC Threshold is the "trigger point" for invoking a rate decrease under the DDC. The DDC Threshold is specified for the end of FY 2008 in Table D.

Where AMNR is generation function modified net revenues, as accumulated since FY 1999, at the end of FY 2008. The forecast of AMNR is used to determine if the DDC Threshold has been reached, and the required Distribution Amount to be distributed. The forecast of AMNR through the end of each fiscal year will be calculated by determining the accumulated annual Modified Net Revenue (MNR) during the period.

Where the MNR for FY 2008 is defined as generation function accrued revenues less accrued expenses (in accordance with Generally Accepted Accounting Principles), with three exceptions:

(1) The calculation of MNR will exclude the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities (including Supplemental standards issued by FASB and interpretations regarding derivatives and hedging activities), and actual Energy Northwest (EN) debt service. (BPA has adopted FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities as amended by FASB Statements 137, 138, and 149 and interpreted by Derivatives*

Implementation Group issues (together, “FAS 133”) as of October 1, 2000.)

(2) The calculation of MNR will include forecast EN debt service identified in the WP-07 Final Supplemental Studies.

(3) The forecast of MNR will be based on actual generation function revenues and expenses for the first three quarters of the year and forecast results for the remainder of the year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power. The transmission function accrued revenues and expenses are excluded. The MNR includes impacts on forecast revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement.

(b) Converting the DDC Amount to a Percentage

Once the DDC Amount is determined, that amount will be converted to the DDC Percentage. The DDC Amount is the percentage decrease applied to customers’ HLH and LLH Energy, and Load Variance rates under the firm power rate schedules subject to the DDC adjustment. The DDC Percentage applies as follows:

(1) The DDC Percentage is calculated by dividing the DDC Amount by the most current forecast of HLH, LLH, and Load Variance revenues from products subject to the DDC. The DDC Percentage cannot be so large that it reduces the LLH energy rate below 1 mill/kWh.

(2) For products subject to the DDC, the DDC Percentage will be applied to HLH and LLH Energy rates and the Load Variance rate for the 12 months beginning in October 2008 and ending September 2009.

2. DDC Adjustment Timing

In early October 2008, the Administrator will determine whether the expected value of the AMNR forecast at the end of that fiscal year is above the DDC Threshold. If the AMNR is forecast to be above the DDC Threshold, the Administrator will propose, by early October, to assess a dividend distribution adjustment to applicable rates for power deliveries beginning in October 2008 (FY 2009).

Customers will be notified, on or about mid-October, of the percentage decrease applicable to the base, if any, due to the DDC. The rates used to calculate the customers' bills for FY 2009 will reflect the DDC decrease.

(a) DDC Notification Process

BPA shall follow the following 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 AMNR.

For the 2nd and 3rd Quarter Review, BPA shall post to its external web site (www.bpa.gov) the preliminary, unaudited *end-of-year* forecast of AMNR attributable to the generation function.

(2) Notice of DDC Trigger

BPA shall complete a forecast of current fiscal end-of-year AMNR in late September 2008. BPA shall notify all customers and rate case parties by early October 2008 if the expected value of the AMNR forecast falls above the DDC Threshold for the DDC applicable to FY 2009, and, if so, by mid-October the extent to which BPA intends to adjust rates due to the DDC. Notification will be posted on BPA's web site, and will include the audited AMNR for FY 2007, the forecast of end-of-year FY 2008 AMNR, the calculation of the Dividend Amount, and the FY 2009 DDC Percentage. The notice shall also describe the data and assumptions relied upon by BPA for the AMNR determination. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

If the FY 2008 AMNR is forecast to be above the DDC Threshold, BPA staff shall conduct a public forum in mid-October 2008 to explain the AMNR forecast, the calculation of the Dividend Amount and the DDC Percentage, and to demonstrate that the DDC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.

No later than October 31, 2008, BPA will post to the BPA web site the final calculation of the adjustment (as a percentage) to each product and benefit subject to the DDC as described above.

G. Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) is a charge intended to recover costs as specified herein. This Surcharge is a separate adjustment from the NFB Adjustment.

The Surcharge addresses the fact that the CRAC does not produce revenues until the year following the fiscal year in which Financial Effects contributing to the triggering of the CRAC occur. The Surcharge may be implemented in FY 2009 if the events required to impose the Surcharge occur in that fiscal year.

The Surcharge applies to HLH and LLH Energy, Demand, and Load Variance sales for power customers under the following firm power rate schedules:

- PF-07R [Preference (excluding the PF Slice Product) and PF Exchange Power];
- Industrial Firm Power (IP-07R);
- New Resource Firm Power (NR-07R); and
- BPA's contractual obligations for Irrigation Rate Mitigation Product sales.

The Surcharge does not apply to sales under the following:

- the PF Slice Product;
- Pre-Subscription contracts to the extent prohibited by such contracts; or
- DSI financial benefits.

1. Definitions

(a) An NFB <u>Trigger Event</u> is one of the following four kinds of events that results in changes to BPA's FCRPS ESA obligations compared to those in the WP-07 Final Supplemental Proposal 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 a NMFS-issued FCRPS BiOp, 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 NMFS FCRPS BiOp; or

(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.

(b) Financial Effects of a Trigger Event are net reductions in BPA net revenue (if any) 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, Corps of Engineers and Bureau of Reclamation Operations and Maintenance expenses, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations in the WP-07 Final Supplemental Proposal as modified prior to this Trigger Event. These effects are the total effects on the Federal System, including the effects borne directly by Slice Customers.

(c) The Agency Within-year TPP is the probability that the Agency (*i.e.*, 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 occurred, and which 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), funds available from Energy Northwest refinancing under the Debt Optimization Program, any expense reductions and revenue increases, 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 WP-07 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, prepayments to Treasury required or called for by the Debt Optimization Program, 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 this surcharge provision.

(e) Revenue Basis is the 12-month totals of revenue from firm power sales subject to the Surcharge for FY 2008.

(f) Customers and holders of benefit contracts (collectively Customers) is intended to represent those that are obligated to recover the costs as specified herein.

(g) 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. Criteria for Assessing the Surcharge

The Surcharge will be assessed if: (i) a Trigger Event occurs in FY 2009; and (ii) the Agency Within-year TPP for FY 2009 is calculated to be less than

80 percent when the Financial Effects of the Trigger Event, but not the revenues from the Surcharge, are taken into account. If this Agency Within-year TPP is equal to or above 80 percent, then no Surcharge will be assessed. If the Agency Within-year TPP is below 80 percent in FY 2009, but no Trigger Event is deemed to have occurred in the fiscal year, then no Surcharge will be assessed. 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.

A Trigger Event may have Financial Effects in more years than the fiscal year in which the Trigger Event occurs. If such a Trigger Event has occurred prior to FY 2009 that will have Financial Effects in FY 2009, the Trigger Event will be deemed to have occurred in FY 2009 as well, and subsections G.3, G.5, and G.6 will be used for FY 2009 to determine whether the implementation of a Surcharge is warranted. 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.

The earliest time a determination of whether to levy a Surcharge for FY 2009 can be made is during the CRAC/NFB/DDC calculations in August or September of the year in which the Trigger Event occurs (*i.e.*, August or September of FY 2008).

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.

3. Formula for Calculating the Financial Effects and the Surcharge Amount

The calculation of the Financial Effects will be determined as follows, making use of the best information available at the time:

Financial Effects =

Expected Value Modified Net Revenue without Trigger Event

Minus

Expected Value Modified Net Revenue with Trigger Event

Where:

(a) The Expected Value Modified Net Revenue without Trigger Event is BPA's projection of what the Modified Net Revenues would be at the end of the fiscal year assuming the Financial Effects of the Trigger Event did not take place. Such projection will be based on actual generation function revenues and expenses to the extent available and forecast results for the remainder of the fiscal year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, including BPA's best estimate of 4(h)(10)(C) credits.

(b) The Expected Value Net Revenue with Trigger Event is the identical projection as made in (1) above, except that BPA will assume the Financial Effects of the Trigger Event did take place.

The calculation of the Surcharge Amount will be determined as follows, making use of the best information available at the time:

The Surcharge Amount =

Financial Effects

Minus

Expense Changes Borne by Slice Customers

Where:

(a) The Expense Changes Borne by Slice Customers are the estimated costs subject to the Annual True-up Adjustment for Actual Costs.

4. This section is left blank intentionally.

5. Calculating the Portion of the Surcharge and the Payment Schedule for Other Customers

Each Customer Percentage will be multiplied by the Surcharge Amount, and divided by the number of billing months payable before the end of the then current fiscal year to determine each customer's Monthly Surcharge, subject to the limit set forth in subsection G.2 above. The Monthly Surcharge will be added to each customer's bill for each billing month payable before the end of the current fiscal year. In 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.

6. Surcharge Notification Process

BPA shall use the following procedures depending on whether one or both of the criteria defined in subsection G.2 occur:

(a) Notification Procedures When a Trigger Event and Agency Within-year TPP Criterion Occur at Different Times During the Same Fiscal Year

(1) Notice of Trigger Event Only

If, at the time a new Trigger Event (*i.e.*, not a deemed Trigger Event) occurs, BPA has not determined that the Agency Within-year TPP is below 80 percent, then BPA shall notify customers within seven (7) days of the occurrence of the Trigger Event. This initial notice will be posted to BPA's web site and provided by e-mail to those listed on the service list for the WP-07 rate proceeding. Such notice will include a description of the Trigger Event and the time and location of a public workshop to be conducted no later than two weeks after the issuance of the notice.

At the workshop, 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 Staff will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the customers' request, Power Services Account Executives shall provide customers their Customer Percentages of the Surcharge Amount or benefit reduction, calculated pursuant to subsection G.5.

No Surcharge will be assessed under this subsection G.6.(a)(1) until the procedural requirements of subsection G.6.(a)(2) have been satisfied.

(2) Notice of Agency Within-year TPP Falling Below 80 Percent Following a Trigger Event

If, at some time later in the 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 notice will be posted to BPA's web site and provided by e-mail to those listed on the service list for the WP-07 BPA rate proceeding.

Such notice will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notice. This notice will also include updated calculations of the Financial Effects and the Agency Within-year TPP. Concurrently, BPA's Power Services Account Executives will inform customers of their Customer Percentages of the

Surcharge Amount or reduction to their benefits due to the Surcharge, as applicable.

At this workshop, BPA will explain the calculation of the Agency Within-year TPP and the Surcharge Amount, as set forth in subsections G.2, G.3, and G.5, including the monthly shape of payments. BPA will provide data and assumptions used in these calculations. BPA Staff will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(b) Notification Procedures when Trigger Event and Agency Within-year TPP Criterion Occur at the Same Time

If a Trigger Event has occurred and BPA concurrently determines, that the Agency Within-year TPP is below 80 percent, then BPA shall notify customers of those two events within seven (7) days of the Trigger Event. In addition, this notice will be posted to BPA's web site and provided by e-mail to those listed on the service list for the WP-07 BPA rate proceeding.

This notice will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notice. Such notice will also include BPA's calculations of the Financial Effects and the Agency Within-year TPP. Concurrently, BPA's Power Services Account Executives will inform customers of their Customer Percentages of the Surcharge Amount.

At this workshop, BPA will explain the calculations of the Agency Within-year TPP and the Surcharge Amount, as set forth in Subsections G.2, G.3, and G.5, including the monthly shape of payments. BPA will provide data and assumptions used in these calculations. BPA Staff will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

7. Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notice to each Customer in accordance with the notice provisions of its BPA contract no later than seven (7) days following the conclusion of the workshop described in subsection G.6.(a)(2) or G.6.(b). Such Final Notice will state the monthly Surcharge Amount and the total Surcharge Amount to be recovered from each customer by September 30 of the fiscal year that the Surcharge is in effect.

The monthly Surcharge Amount will be included on a bill to power customers, and will be payable in accordance with the applicable payment provisions of the customer's power contract. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification described in this subsection G.7.

8. Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notice described in subsection G.7 of implementation of a Surcharge, BPA will convene two or more meetings, the schedule for which will not exceed sixty (60) days.

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 subsection G.8, 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, or remove it entirely if one or more of the following occur:

(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;

(b) an updated Surcharge calculation results in a change compared to the Surcharge calculated in subsection G.7.

H. Excess Factoring Charges

1. Excess Within-Day Factoring Charge

The within-day factoring test compares the hour-by-hour shape of the customer's load to the customer's hour-by-hour energy take from BPA within a day. This test identifies whether or not the hour-by-hour shape of the customer's take from BPA has used more within-day factoring service, measured in kWh, than the underlying load would have used.

Excess Within-Day Factoring Charge, for any hour(s) in the month, applies to amount of hourly energy in excess of the authorized maximum energy amounts defined by the customer's within-day load shape.

(a) *The total amount of Excess Within-Day Factoring Charge during the HLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh;

(2) Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California Independent System Operator (CAISO) Supplemental Energy price (NP15) and the lowest hourly HLH CAISO Supplemental Energy price (NP15).

(b) *The total amount of Excess Within-Day Factoring Charge during the LLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh;

(2) Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH CAISO Supplemental Energy price (NP15) and the lowest hourly LLH CAISO Supplemental Energy price (NP15).

In the event that the index for ISO Supplemental Energy expires, that index will be replaced for the purpose of deriving Excess Within-Day Factoring Charges by another hourly energy index at a hub at which Northwest parties can trade.

2. Excess Within-Month Factoring Charges

The within-month factoring test compares the day-by-day shape of the customer's load to the customer's day-to-day energy take from BPA within a month. This test identifies whether the day-to-day shape of the customer's take from BPA used more within-month factoring service than the underlying load would have used. The within-day factoring test (see above) is not equipped to identify a factoring service issue if, for example, the customer resource deliveries were zero for a particular day. The within-month factoring test is equipped to address that type of instance. The within-month factoring test establishes an upper and lower boundary for each diurnal period of the day. Excess within-month factoring for each diurnal period is the greater of: (1) the sum of the amounts greater than the upper boundary; or (2) the sum of the amounts less than the lower boundary.

Excess Within-Month Factoring Charge applies to that amount of energy take that either exceeds or falls short of a range defined by: (1) a flat load placement on BPA; and (2) a load placement that follows the customer's actual load shape.

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

(a) *The Excess Within-Month Factoring during the HLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh.

(2) The highest peak Dow Jones Mid-Columbia (DJ Mid-C) Index price for firm power during the month LESS the lowest peak DJ Mid-C Firm Index price for firm power during the month.

(3) The highest average HLH CAISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays and holidays) during the month LESS the lowest average HLH CAISO Supplemental Energy price (NP15) for the same period.

(b) *The Excess Within-Month Factoring during the LLHs of the month shall be billed the greater of:*

(1) 5 mills/kWh.

(2) The highest off-peak DJ Mid-C Index price for firm power during the month LESS the lowest off-peak DJ Mid-C Index price for firm power.

(3) The highest average LLH CAISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sundays and holidays) during the month LESS the lowest average LLH CAISO Supplemental Energy price (NP15) for the same month in the same time period.

The DJ Mid-C Index definitions for HLHs (or Peak) and LLHs (or off-peak) will be adjusted, as necessary, to be consistent with (comport with) BPA's definition for HLH and LLH periods.

In the event that the index for CAISO Supplemental Energy or DJ Mid-C Index expires, that index will be replaced for the purpose of deriving Excess Within-Month Factoring Charges by another hourly or diurnal energy index at a hub at which Northwest parties can trade.

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

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make contractual commitments to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser, subject to satisfying the following condition:

Equivalent NPV Revenues: Forecast revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the NR rate schedule Section II 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 Demand and Energy (and Load Variance, if appropriate) charges specified in the NR rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

J. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make contractual commitments to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under the rate schedule. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser, subject to satisfying the following condition:

Equivalent NPV Revenues: Forecast revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in the PF rate schedule Section II 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 Demand and Energy (and Load Variance if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF 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 will survive and be fully enforceable until such time as they are fully satisfied.

K. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from 0-40 mills/kWh that a customer elects to pay and which is applied to the amount of Environmentally Preferred Power (EPP) energy that the customer has elected to purchase. Forecast GEP revenue is the estimated avoided cost of renewable energy credit sales based on credits produced by BPA's renewable resource portfolio. BPA guarantees the customer paying the premium that BPA will produce an amount of renewable energy credits equal to the amount of energy subject to this adjustment. The GEP will be charged in a line item on the monthly power bill of each participating customer. The negotiated GEP will be based on cost and the market value of the non-power renewable attributes as well as applicable costs associated with the purchase. Such costs may include, but are not limited to:

- Avoided Costs of renewable energy credits based on existing BPA resources
- Avoided Costs of renewable energy credits based on new or proposed BPA resources
- Endorsement fees for specific EPP resources.
- Actual costs of Market purchases of renewable energy credits.

2. Calculation and Application of the Premium

(a) Determination of the Premium

For a customer buying power from BPA under a requirements firm power sales contract, the amount of EPP and the GEP will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation. The charge will not exceed 40 mills/kWh and may be as low as zero. The premium will be zero if the avoided cost of the GEP resource(s) dedicated to the customer is zero. The GEP will recover the average forecast avoided cost of the renewable resource credit portfolio inventory available for this product.

(b) Determination of Individual Customer GEP

(1) Customers will be provided notice of the availability of specific GEP products and associated premiums. The total GEP for the customer will be based on the customer's elections of product amounts and content.

(2) The average annual energy charge will be calculated as the average per-kWh charge for an annual flat undelivered product using the energy charges applicable to the customer. Where customers are purchasing under more than one rate schedule, the average energy charge will be calculated using expected loads and applicable rate schedules.

(3) The individual customer GEP for billing will be the total cost of the product selected by the customer minus the average annual energy charge.

(c) Application of the GEP

The GEP will be applied after BPA has determined all other charges and credits except the Conservation Rate Credit (CRC) line item on the participating customer's power bill.

(d) Billing for the Premium

The customer's bill will include a line item showing the kWh amount of EPP purchased times the GEP for the products elected and the total cost. The calculation will appear as:

(EPP amount) kWh * GEP mills/kWh = $X

L. Low Density Discount (LDD)

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of the PF Preference Rate, the PF Exchange Rate, and the New Resource Rate: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase

Charges, Excess Factoring Charges, transmission charges, or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

(a) The Kilowatt-hour/Investment Ratio

The kWh/Investment (K/I) ratio is calculated annually based on the data supplied by June 30 for the previous CY. The K/I ratio is calculated by dividing the Purchaser's Total Retail Load during the CY by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of the CY.

(b) The Consumers/Mile of Line Ratio

The Consumers/Mile of Line (C/M) ratio is determined annually using the data supplied by June 30 for the previous CY. The C/M ratio is calculated by dividing the maximum number of consumers within the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as additional billed consumers.

The number of pole miles of distribution line means the end-of-CY pole miles. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kilovolt (kV) or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

These calculations shall be based on CY data provided from the Purchaser's annual financial and operating reports. The Purchaser shall certify that the data submitted is correct and that no loads gained as provided in section 6, Retail Access Exclusion, are receiving LDD benefits.

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the PNW. For Purchasers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the PNW and on the Purchaser's entire electric utility inside and outside the PNW. BPA will apply the eligibility criteria and discount percentages to the Purchaser's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Purchaser's eligibility for the LDD will 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 Purchaser with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

A Purchaser who has not provided BPA with the requisite data needed to calculate the K/I and C/M ratios by June 30 of each year, for the prior CY, shall be declared ineligible for the LDD, effective the upcoming October 1.

If a Purchaser's data was submitted on time, and a revision is necessary to the data, the revised data must be resubmitted no later than 12 months after the original submission date to be considered for an adjustment.

2. Eligibility Criteria

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

(a) the Purchaser must serve as an electric utility offering power for resale;

(b) the Purchaser must agree to pass the benefits of the discount through to the Purchaser's eligible consumers within the region served by BPA;

(c) the Purchaser'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;

(d) the Purchaser's K/I ratio must be less than 100; and

(e) the Purchaser's C/M ratio must be less than 12.

3. Discounts

The Purchaser shall be awarded the following discount beginning October 1, 2008, in accordance with section 4 below. The discount will be the sum of the two potential discounts for which the Purchaser qualifies, based on the following Table F. The discount shall not exceed 7 percent.

Table F
LDD Percentage Discount Table

Percentage Discount	***Applicable Range for kWh/Investment (K/I) Ratio***	***Applicable Range for Consumers/Mile (C/M) Ratio***
0.0%	$35.0 \le X$	$12.0 \le X$
0.5%	$31.5 \le X < 35.0$	$10.8 \le X < 12.0$
1.0%	$28.0 \le X < 31.5$	$9.6 \le X < 10.8$
1.5%	$24.5 \le X < 28.0$	$8.4 \le X < 9.6$

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
2.0%	$21.0 \le X < 24.5$	$7.2 \le X < 8.4$
2.5%	$17.5 \le X < 21.0$	$6.0 \le X < 7.2$
3.0%	$14.0 \le X < 17.5$	$4.8 \le X < 6.0$
3.5%	$10.5 \le X < 14.0$	$3.6 \le X < 4.8$
4.0%	$7.0 \le X < 10.5$	$2.4 \le X < 3.6$
4.5%	$3.5 \le X < 7.0$	$1.2 \le X < 2.4$
5.0%	$X < 3.5$	$X < 1.2$

4. LDD Phase-Out Adjustment

If the Purchaser satisfies the eligibility criteria (2. a. through e.), and the calculated discount differs from the existing discount by more than one-half of 1 percent, the applicable discount will be:

(a) the existing discount plus one-half percent if the calculated discount exceeds the existing discount; or

(b) the existing discount minus one-half percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each October 1 until the then-current calculated discount is fully phased out.

The Purchaser is not eligible to receive any discount, effective each October, if the Purchaser fails to meet the eligibility criteria in section 2. a. through e.

5. Additional Adjustment for Very Low Densities

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

6. Retail Access Exclusion

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

7. Application of the LDD to Slice Product

To be eligible for the LDD, customers that purchase the Slice product must meet the eligibility criteria under section 2.

The LDD benefit for Slice customers will be determined and applied as follows:

By September of each year, BPA will establish a mills/kWh discount rate for each one-half percent discount bracket, from 0.5 percent to 7 percent. The mills per kWh discount rate for each bracket will be determined by using billing data of customers within the same non-Slice LDD percentage bracket. Those customers' total dollars in non-Slice LDD discounts they received will be divided by the total eligible energy purchased. This will result in a mills/kWh rate that can then be used as the yearly/monthly discount for a Slice customer that is eligible, under section 3, to receive the same discount. BPA will use billing data from the previous CY from the non-Slice LDD recipients when calculating the mills/kWh discount rate for Slice product recipients. When there are no non-Slice LDD recipients available in a given discount bracket to calculate the mills/kWh value, it is appropriate to determine a linear relationship using a regression analysis to arrive at a mills/kWh value for that bracket. When there is an increase or decrease in the PF rate for HLH and LLH billing determinants, not due to the Targeted Adjustment Charge (TAC), CRAC, NFB Adjustment, Emergency NFB Surcharge, or the DDC, the regional average increase or decrease will be applied to the mills/kWh rate that coincides with the increase or decrease in rate(s) for the non-Slice LDD recipients for the same period.

The rate will only be applied to that portion of Slice power being purchased that is requirements power. This quantity is defined in the Slice Contract as Critical Slice Amount. The annual Slice True-Up will include an LDD true-up if based on estimates. If it is based on after-the-fact monthly data, no true-up is necessary.

M. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customers' rate choices and maintaining the distinction would increase BPA's overall cost of providing rate choices. For administrative simplicity, upon mutual agreement between BPA and the customer, BPA may offer to meld the customer's rate choices into a single composite set of rates that reflects the specific choices made by the customer. BPA will ensure that this melded set of rates will result in a bill that is nearly mathematically equivalent to applying the customer's individual choices throughout the rate period. BPA will provide the affected customer the calculations it used to establish the melded rates and provide 30 days for the customer to review and accept the melding calculation before it implements the melded rates. Melded rates established by BPA will continue until one of the customer's rate choices expires, or a rate adjustment occurs that is provided for under the chosen rate schedules (*e.g.*, CRAC), or a significant change in the loads applicable to the rates occurs.

N. Slice True-Up Adjustment

1. Calculation of the Annual True-Up

Following the end of each Fiscal Year (FY), BPA will calculate the difference between the Actual Slice Revenue Requirement for such FY and the average Slice Revenue Requirement upon which the applicable Slice rate is based. The Actual Slice Revenue Requirement for the applicable FY is the sum of the final audited expenditures and revenues as reflected on BPA's financial statements, corresponding to those Power Services expense and revenue categories that are included in the Slice Revenue Requirement. BPA's financial statements contain expenses and credits that are in accordance with Generally Accepted Accounting Principles (GAAP). For example, after the end of FY 2009, BPA will calculate the difference between the Actual Slice Revenue Requirement for the Fiscal Year (FY) ending September 30, 2009 (FY 2009) and the average Slice Revenue Requirement for FY 2007-2009 determined in the WP-07 Supplemental Rate Case (*see* Table 1, Slice Product Costing and True-Up Table).

The difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement will be the basis for the Slice True-Up Adjustment Charge (or Credit). This difference, if the Actual Slice Revenue Requirement for FY 2009 exceeds the average Slice Revenue Requirement determined in the WP-07 Supplemental Rate Case, can be positive, which results in a True-Up Adjustment Charge. Alternatively, this difference can be negative, if the Actual Slice Revenue Requirement for FY 2009 is less than the average Slice Revenue Requirement determined in the WP-07 Supplemental Rate Case, which results in a True-Up Adjustment Credit.

To calculate each Slice customer's share of this difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement determined in the WP-07 Supplemental Rate Case, BPA will multiply this difference by the Slice customer's Selected Slice Percentage. For example, if the Slice customer's Selected Slice Percentage is 5 percent, then the difference will be multiplied by 0.05 to calculate the Slice customer's share of the difference. These amounts will be included on Slice customers' bills as the Slice True-Up Adjustment Charges or Credits.

2. Slice Implementation Expenses

In addition, following the end of each FY, BPA will calculate the amount of Slice Implementation Expenses incurred during that FY. Slice customers will be charged for 100 percent of these expenses, and these expenses will be allocated on the basis of each customer's Selected Slice Percentage, relative to the total of all customers' Selected Slice Percentages. For example, if the Slice customer's Selected Slice Percentage is 5 percent, this percentage is divided by the total percentage of Slice sold (currently 22.6278 percent) to obtain that customer's share of the Slice Implementation Expenses (*e.g.*, 5 percent divided by

22.6278 percent equals 35.35 percent). These amounts will be included on Slice customers' bills as Slice True-Up Implementation Expense charges at the same time as the Slice True-Up Adjustment Charges or Credits.

3. Individual Charges and Individual Credits

For some customers who purchase additional services from BPA, or who elect certain contractual options, BPA will calculate the amount of Individual Charges that will be added to their bills at the same time as the Slice True-Up Adjustment Charge. For some customers who elect certain contractual options, BPA will calculate the amount of Individual Credits that will be factored into their bills at the same time as the Slice True-Up Adjustment Charge or Credit.

Table 1
Slice Product Costing and True-Up Table

($000s)

		Audited Actual Data	FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		$ 263,669	$ 188,688	$ 293,700
5	BUREAU OF RECLAMATION		$ 71,654	$ 74,760	$ 82,100
6	CORPS OF ENGINEERS		$ 161,519	$ 165,742	$ 179,500
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 24,932	$ 25,314	$ 31,522
8	**Sub-Total**		**$ 521,774**	**$ 454,504**	**$ 586,822**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		$ 16,968	$ 17,354	$ 20,909
11	SPOKANE GENERATION SETTLEMENT		$ -	$ -	$ -
12	**Sub-Total**		**$ 16,968**	**$ 17,354**	**$ 20,909**
13	**Non-Operating Generation**				
14	TROJAN DECOMMISSIONING		$ 5,400	$ 4,700	$ 2,500
15	WNP-1&3 DECOMMISSIONING		$ 200	$ 200	$ 400
16	**Sub-Total**		**$ 5,600**	**$ 4,900**	**$ 2,900**
17	**Contracted Power Purchases**				
18	PNCA HEADWATER BENEFIT		$ 1,714	$ 1,714	$ 1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)				
20	DSI MONETIZED POWER SALE		$ 59,000	$ 59,000	$ 54,999
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**$ 60,714**	**$ 60,714**	**$ 56,713**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**$ 6,762**	**$ 6,811**	**$ 1,107**
27	IOU RESIDENTIAL EXCHANGE		**$ 301,000**	**$ 301,000**	**$ 251,161**
28	**Renewable Generation (expenses related to reinvestment removed)**		**$ 30,289**	**$ 34,719**	**$ 41,050**
29	**Generation Conservation**				
30	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000	$ 5,812
31	ENERGY EFFICIENCY DEVELOPMENT		$ 12,885	$ 12,908	$ 22,000
32	ENERGY WEB		$ 1,000	$ 1,000	$ 7,000
33	**LEGACY (Until 11/1/03 this was included with line 72)**		$ 3,728	$ 2,638	$ 2,114
34	MARKET TRANSFORMATION		$ 10,000	$ 10,000	$ 10,000
35	TECHNOLOGY LEADERSHIP		$ 1,300	$ 1,300	$ 1,600
36	INFRASTRUCTURE SUPPORT AND EVALUATION		$ 1,000	$ 1,000	
37	BI-LATERAL CONTRACT ACTIVITY		$ 1,000	$ 1,000	
38	**Sub-Total**		**$ 35,913**	**$ 34,846**	**$ 48,526**
39	CONSERVATION RATE CREDIT		$ 36,000	$ 36,000	$ 32,000
40	**Power System Generation Sub-Total**		**$ 1,015,019**	**$ 950,848**	**$ 1,041,188**
41					
42	**PBL Transmission Acquisition and Ancillary Services**				
43	**PBL Transmission Acquisition and Ancillary Services**				
44	PBL - TRANSMISSION & ANCILLARY SERVICES				
45	Canadian Entitlement Agreement Transmission Expenses		$ 24,806	$ 25,550	$ 27,000
46	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,775	$ 1,825	$ 1,000
47	3RD PARTY GTA WHEELING		$ 47,000	$ 47,000	$ 50,370
48	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				$ -
49	RESERVE & OTHER SERVICES		$ 8,462	$ 8,462	$ 6,800
50	TELEMETERING/EQUIP REPLACEMT		$ 200	$ 200	$ 50
51	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**$ 82,243**	**$ 83,037**	**$ 85,220**
52					
53	**Power Non-Generation Operations**				
54	**PBL System Operations**				
55	EFFICIENCIES PROGRAM (omit TMS expenses)		$ -	$ -	$ -
56	INFORMATION TECHNOLOGY		$ -	$ -	$ 5,423
57	GENERATION PROJECT COORDINATION		$ 5,637	$ 5,738	$ 7,648
58	SLICE IMPLEMENTATION (omit - calculated separately)				
59	**Sub-Total**		**$ 5,637**	**$ 5,738**	**$ 13,071**
60	**PBL Scheduling**				
61	OPERATIONS SCHEDULING		$ 8,758	$ 9,051	$ 9,571
62	OPERATIONS PLANNING		$ 5,202	$ 5,358	$ 5,969
63	**Sub-Total**		**$ 13,960**	**$ 14,409**	**$ 15,540**
64	**PBL Marketing and Business Support**				
65	SALES & SUPPORT		$ 15,884	$ 16,278	$ 18,988
66	Contractual exclusion		$ (5,360)	$ (5,360)	$ (5,360)
67	Implementation Expense Exclusions - Add back				
68	PUBLIC COMMUNICATION & TRIBAL LIAISON				
69	STRATEGY, FINANCE & RISK MGMT		$ 10,965	$ 11,359	$ 14,820
70	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 845	$ 840	$ 3,123
71	CONSERVATION SUPPORT (EE staff costs)		$ 6,441	$ 6,692	$ 7,996
72	**Sub-Total**		**$ 28,776**	**$ 29,808**	**$ 39,567**
73	**Power Non-Generation Operations Sub-Total**		**$ 48,372**	**$ 49,955**	**$ 68,178**
74					
75	**Fish and Wildlife/USF&W/Planning Council**				
76	**BPA Fish and Wildlife (includes F&W Shared Services)**				
77	FISH & WILDLIFE		$ 143,000	$ 143,000	$ 199,998
78	F&W HIGH PRIORITY ACTION PROJECTS				
79	**Sub-Total**		**$ 143,000**	**$ 143,000**	**$ 199,998**
80	**PBL-USF&W Lower Snake Hatcheries**				
81	USF&W LOWER SNAKE HATCHERIES		$ 18,600	$ 19,500	$ 19,690
82	**PBL - Planning Council**				
83	PLANNING COUNCIL		$ 9,085	$ 9,276	$ 9,450
84	**PBL - ENVIRONMENTAL REQUIREMENTS**				
85	ENVIRONMENTAL REQUIREMENTS		$ 500	$ 500	$ 300
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 171,185**	**$ 172,276**	**$ 229,438**

Table 1, continued
Slice Product Costing and True-Up Table

87					
88	**BPA Internal Support**				
89	**CSRS/FERS**				
90	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$ 10,550	$ 9,000	$ 15,277	
91	**Corporate Support - G&A (excludes direct project support)**				
92	CORPORATE G&A	$ 50,247	$ 51,753	$ 44,994	
93	**TBL Supply Chain - Shared Services**	$ 368	$ 374		
94	**General and Administrative/Shared Services Sub-Total**	**$ 61,165**	**$ 61,127**	**$ 60,271**	
95					
96	**Bad Debt Expense**				
97	**Other Income, Expenses, Adjustments**	**$ 1,800**	**$ 1,800**	**$ -**	
98	**Non-Federal Debt Service**				
99	**Energy Northwest Debt Service**				
100	COLUMBIA GENERATING STATION DEBT SVC	$ 195,690	$ 217,856	$ 224,801	
101	WNP-1 DEBT SVC	$ 147,941	$ 165,916	$ 169,509	
102	WNP-3 DEBT SVC	$ 151,724	$ 160,092	$ 150,983	
103	EN RETIRED DEBT				
104	EN LIBOR INTEREST RATE SWAP				
105	**Sub-Total**	**$ 495,355**	**$ 543,864**	**$ 545,293**	
106	**Non-Energy Northwest Debt Service**				
107	TROJAN DEBT SVC	$ 8,605	$ 7,888	$ -	
108	CONSERVATION DEBT SVC	$ 5,203	$ 5,198	$ 5,188	
109	COWLITZ FALLS DEBT SVC	$ 11,619	$ 11,583	$ 11,571	
110	WASCO DEBT SVC	$ -	$ 1,664	$ 2,168	
111	**Sub-Total**	**$ 25,427**	**$ 26,333**	**$ 18,927**	
112	**Non-Federal Debt Service Sub-Total**				
113	Depreciation (excl. TMS)	$ 118,058	$ 121,829	$ 118,832	
114	Amortization (excludes ConAug amortization)	$ 55,567	$ 60,241	$ 56,412	
115	**Total Operating Expenses**	**$ 2,074,191**	**$ 2,071,310**	**$ 2,223,759**	
116					
117	**Other Expenses**				
118	Net Interest Expense	$ 163,080	$ 173,193	$ 160,845	
119	LDD	$ 22,289	$ 22,612	$ 25,219	
120	Irrigation Rate Mitigation Costs	$ 10,000	$ 10,000	$ 12,000	
121	**Sub-Total**	**$ 195,369**	**$ 205,805**	**$ 198,064**	
122	**Total Expenses**	**$ 2,269,560**	**$ 2,277,115**	**$ 2,421,823**	
123					
124	**Revenue Credits**				
125	Ancillary and Reserve Service Revs. Total	$ 73,131	$ 61,970	$ 79,306	
126	Downstream Benefits and Pumping Power	$ 8,921	$ 8,921	$ 8,921	
127	4(h)(10)(c)	$ 84,707	$ 84,927	$ 88,480	
128	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 4,600	
129	FCCF				
130	Energy Efficiency Revenues	$ 12,885	$ 12,908	$ 22,000	
131	Miscellaneous	$ 3,420	$ 3,420	$ 3,420	
132	**Total Revenue Credits**	**$ 187,664**	**$ 176,746**	**$ 206,727**	
133					
134	**Augmentation Costs**				
135	**IOU Reduction of Risk Discount (includes interest)**	$ 23,024	$ 23,024		
136	(Net augmentation power costs are not subject to True-Up)				
137	**Forecasted Gross Augmentation Costs**				
138	Residual augmentation cost	$ 49,005			
139	Other augmentation cost	$ 97,062	$ 95,001	$ 161,122	
140	Minus revenues	$ 67,993	$ 42,972	$ 73,667	
141	**Net Cost of Augmentation**	**$ 101,098**	**$ 75,053**	**$ 87,455**	
142					
143					
144	**Minimum Required Net Revenue calculation**				
145	Principal Payment of Fed Debt for Power	$ 202,331	$ 172,483	$ 103,065	
146	Irrigation assistance	$ -	$ 2,950	$ 7,279	
147	Depreciation	$ 118,058	$ 121,829	$ 118,832	
148	Amortization	$ 71,658	$ 76,332	$ 69,748	
149	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ (45,937)	
150	Bond Premium Amortization	$ 613	$ 613	$ 185	
151	Principal Payment of Fed Debt exceeds non cash expenses	$ 57,939	$ 22,596	$ (32,484)	
152	Minimum Required Net Revenues	**$ 57,939**	**$ 22,596**	$ -	
153					**3-Year Total Rev Reqt**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**$ 2,240,934**	**$ 2,198,018**	**$ 2,302,550**	**$ 6,741,502**
155					
156	SLICE TRUE-UP ADJUSTMENT CALCULATION				
157	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Rate Case	**$ 2,252,465**			
158	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Supplemental Rate Case	**$ 2,247,167**			
159	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)				
160	AMOUNT BILLED (22.6278 percent)				
161	Slice Implementation Expenses (not incl. in base rate)				
162	TRUE UP ADJUSTMENT				
163					
164					
165	**SLICE RATE CALCULATION ($)**				
166	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 187,263,943**
167	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,872,639**
168					
169	**ANNUAL BASE SLICE REVENUES**				**$ 508,484,525**
170	**Annual Slice Implementation Expenses**				**$ 2,486,000**
171	**TOTAL ANNUAL SLICE REVENUES**				**$ 510,970,525**

O. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP-07R rate schedule may be adjusted to reflect the negotiated Supplemental Contingency Reserves Adjustment (SCRA) adjustment. Power Services will negotiate with any DSI interested in providing Supplemental Contingency Reserves (Supplemental Reserves). Supplemental Reserves refers to generating capacity, and associated energy, fully available within 10 minutes' notice of a system disturbance. This is a flexible rate that will allow BPA to negotiate company-specific interruption rights and will establish a value tied to the company-specific arrangement based on the amount and quality of reserves provided. The maximum amount Power Services may pay for Supplemental Reserves from a DSI is capped at the rate published in BPA's Final Supplemental WP-07 Rate Proposal for operating reserve capacity that is provided as a generation input to Transmission Services. This maximum value is based on the FERC-approved embedded cost methodology.

The suitability and quality of the Supplemental Reserves will be measured by whether they have certain characteristics, some of which are required and others optional. Any Supplemental Reserves purchased by Power Services must be consistent with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria:

1. The interruptible load must be offline within five minutes after a call by BPA;

2. In the event of a system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties; and

3. The interruptible load must be available to be offline for up to 60 minutes.

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

1. The extent to which Power Services has the discretion when and how to use all operating reserves and to determine what resources to call on in the event of a system disturbance; and

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

Pursuant to established criteria met and performance demonstrated, BPA will satisfy its obligation to provide a reserves credit or payment to the DSI through Transmission Services' Transmission Contracts and the Stability Reserves Credit, or through other contracts as negotiated.

P. Targeted Adjustment Charge (TAC)

1. Availability

The TAC pertains to the PF rate schedule, except for the Slice Product and the PF Exchange Power Product. The TAC also applies to purchases under the NR Rate. The TAC applies to firm power requirements service to regional firm load that results in an unanticipated increase in BPA's projected loads within the rate period. The TAC will be applied to the applicable rate for requirements service requested after June 30, 2007. TAC also applies to customers that add load through retail access, including load that was once served and returns under retail access.

TAC will also apply to subsequent requests made by a customer under a Subscription contract for requirements service for such customer's load(s) that had been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources. The TAC will not apply to purchases included in a customer's initial Subscription contract.

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer, and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply the PF-07R rate. The TAC will apply if the annexed requirements service has been previously served by that customer's 5(b)(1)(A) or 5(b)(1)(B) resources.

Where a public agency customer annexes residential and small farm load previously served by an IOU, and such load was receiving BPA power or financial benefits through a Residential Purchase and Sale Agreement (RPSA) as amended, the IOU will return a pro rata amount of its RPSA benefits calculated in annual aMW by assignment to BPA. BPA will provide such benefits to the public agency customer by exempting from the TAC charge that amount of annexed load. BPA will deliver an amount of firm power to the annexing public agency customer at the PF-07R rate equal to the amount of financial benefit assigned by the IOU to BPA. This, in effect, will reduce the overall TAC charge. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the benefits assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the Customer's contract or until the end of the rate period, whichever occurs first. The TAC will not apply to unanticipated loads less than 1 aMW per year if it is determined to be inconsequential to overall costs. For any TAC load greater than 1 aMW per year, the entire amount will be subject to the TAC, not just the amount above 1 aMW. If a new public requests service, the TAC, if any, will apply until September 30, 2009.

If a customer is serving a portion of its load with a certifiable renewable resource eligible for the Conservation Rate Credit (CRC), or contract purchases of certified renewable resource power eligible for the CRC for a period less than the term of the customer's BPA requirements firm power contract, then the customer may request, during the FY 2007-09 rate period, requirements firm power service for such load at the end of the specified contract period at the PF Preference (PF-07R) rate without being subject to the TAC. This limited exception applies to the first 200 aMW in any contract year, or to amounts that BPA specifies in accordance with its Policy on the Determination of Net Requirements.

2. Energy Charge

The TAC is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the WP-07 rate schedule, and is applied to that portion of the Purchaser's load that is subject to the TAC. The TAC rate adjustment will be established based on the following formula:

TAC = [(Incr $ * Incr Amt) – (Rate $ * Incr Amt)]/TAC Amt

where:

TAC Amt	=	The amount of load subject to the TAC, determined monthly.
Rate $	=	The monthly PF (or NR) energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy in inventory available to serve this load based on monthly Federal system firm resource capability, estimated using critical water, excluding balancing purchases and purchases for system augmentation, from the WP-07 rate case, with updates if BPA determines that is necessary.
Incr $	=	Monthly cost to BPA, including a handling fee, of incremental power purchases expressed in mills/kWh. These costs also may include, where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities.
Incr Amt	=	Amount of incremental power required, determined monthly and defined as the TAC Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TAC Amt).

TAC = Monthly rate adjustment in mills/kWh.

If Incr $ is less than Rate $, the TAC is 0 mills/kWh.

BPA will calculate the cost (Incr $) per month in mills/kWh of the additional power per month (Incr Amt) for a specific customer request. BPA will establish the cost of the additional power by the following method:

- BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market.

Q. Unauthorized Increase Charge (UAI Charge)

1. Charge for Unauthorized Increase in Demand

The amount of Measured Demand during a billing hour that exceeds the amount of demand the purchaser is contractually entitled to take during that hour shall be billed at the greater of:

(a) Three (3) times the applicable monthly demand charge;

(b) The sum of hourly California Independent System Operator (CAISO) Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or

(c) The sum of hourly CAISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 Nevada-Oregon Border (NOB).

In the event that the hourly CAISO Spinning Reserve Capacity market expires, the Unauthorized Increase Charge for demand shall be the greater of:

(a) Three (3) times the applicable monthly demand charge; or

(b) the sum of hourly or diurnal prices for all HLHs in the month, at a hub at which Northwest parties can trade, established between October 1, 2008, and September 30, 2009.

2. Charge for Unauthorized Increase in Energy

The amount of Measured Energy during a diurnal period of a billing month, day, or hour that exceeds the amount of energy the purchaser is contractually entitled to take during that period shall be billed the greater of:

(a) 100 mills/kWh; or

(b) for the month in question, the greater of:

(1) the highest diurnal Dow Jones Mid-C (DJ Mid-C) Index price for firm power; or

(2) the highest hourly CAISO Supplemental Energy price (NP15).

The DJ Mid-C Index definitions for HLHs (or peak) and LLHs (or offpeak) will be adjusted, as necessary, to be consistent with BPA's definitions for HLH and LLH periods.

In the event that either the CAISO Supplemental Energy price index or the DJ Mid-C Index expires, the index will be replaced for purposes of the Unauthorized Increase Charge for energy by:

(1) the highest price experienced for the month at the NW1 (COB);

(2) the highest price experienced for the month at the NW3 (NOB); or

(3) the highest price experienced 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, 2008, and September 30, 2009.

R. West-wide Price Cap of FPS Sales

BPA will voluntarily agree to limit the price of any sales under the FPS rate schedule to the applicable west-wide price cap, if any, established or approved by the Federal Energy Regulatory Commission.

S. Supplemental 7(b)(3) Rate Charge Adjustment

The Supplemental 7(b)(3) Rate Charge is a utility-specific modification to the Base PF Exchange rate that recovers each utility's allocated share of the rate protection provided pursuant to section 7(b)(2) of the Northwest Power Act. Each utility's Supplemental 7(b)(3) Rate Charge is determined in a section 7(i) rate proceeding based on the Base PF Exchange rate and the ASCs and forecast exchange loads of all utilities assumed in ratemaking to participate in the Residential Exchange Program.

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. If such modification to a participating utility's ASC occurs, BPA will adjust the Supplemental 7(b)(3) Rate Charges of all participating utilities to reflect the new ASC.

Such adjustment of Supplemental 7(b)(3) Rate Charges will be accomplished by substituting the modified ASC in the following table and recomputing column E:

	A	B	C	D	E
	FY 2009 ASC	FY 2009 Load	FY 2009 Allocator	Realloc-ation	7(b)(3) Rate Charge
Avista	$50.28	4152	$47,919	$25,838	$6.22
Idaho Power 1/	$33.86	0	$-	$-	$-
Northwestern Energy	$54.84	928	$14,945	$8,058	$8.68
PacifiCorp	$51.27	9,621	$120,556	$65,009	$6.76
Portland General	$55.61	8,562	$144,441	$77,889	$9.10
Puget Sound Energy	$59.71	11,871	$248,928	$134,231	$11.31
Centralia 1/	$35.56	0	$-	$0	$-
Franklin	$45.74	343	$2,399	$1,293	$3.77
Snohomish 1/	$38.08	0	$-	$-	$-
Total			$579,188	$312,318	

1/ Low ASC utilities not participating in REP.

Where:

- Column A is the participating utility's Average System Cost, expressed in mills/kWh.
- Column B is the forecast exchange load for the participating utility, expressed in gigawatt-hours, as established in the rate case.
- Column C is the product of Column B times the difference between Column A and the unbifurcated PF Exchange rate (38.74 mills/kWh).
- Total of Column C is the sum of the values in Column C.
- Total of Column D is the difference between the Total of Column C and $266,870.
- Column D is the Total of Column D reallocated pro rata over Column C.
- Column E is the new utility-specific Supplemental 7(b)(3) Rate Charge, computed by dividing Column D by Column B.

The adjusted Supplemental 7(b)(3) Rate Charges 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 period the PF Exchange rate herein is in effect.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Actual Partial Service Product – Simple/Complex

The Actual Partial Service Products are Core Subscription products that are available to purchasers who have a right to purchase from BPA for their requirements. These products are intended for customers who have contractual or generating resources with firm capabilities and therefore require a product other than Full Service. The Simple and Complex versions of this product category differ in that the Complex version is subject to the Factoring Benchmark tests in the billing process and to potential Excess Factoring Charges. The Simple version encompasses several possible approaches to customer resource declaration, all of which obviate the need for the Factoring Benchmark tests.

2. Block Product

The Block Product is a Core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available in HLH and LLH quantities per month, with the hourly amount flat for all hours in such periods.

3. Block Product with Factoring

The Block Product with Factoring is a combination of the Block Product with the Core Subscription staple-on product for Factoring Service. Factoring provides the service of distributing Block energy to follow Purchaser hourly load needs to the extent of such Block energy.

4. Block Product with Shaping Capacity

The Block Product with Shaping Capacity is a combination of the Block HLH energy product and the Core Subscription staple-on product for Shaping capacity. Shaping capacity allows the customer to preschedule Block energy with some limited shape among HLHs within a contractually specified bandwidth.

5. 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 AGC 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 contract. 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.

6. 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 purchasers under the Priority Firm Power (PF-07R), New Resources Firm Power (NR-07R), and Firm Power Products and Services (FPS-07R) rate schedules. Such power is not available for 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 Purchaser 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.

7. Core Subscription Products

BPA's Core Subscription Products are described in the BPA Product Catalog. Core Subscription Products are available at the posted rates for customers who have a right to purchase them.

The core products are:

- Actual Partial Service Product – Simple/Complex
- Block Product
- Block Product with Factoring
- Block Product with Shaping Capacity
- Full Service Product

8. Customer System Peak (CSP)

CSP is the largest measured HLH Total Retail Load amount in kilowatts for the billing period.

9. Full Service Product

Full Service is a Core Subscription product that is available to purchasers who have a right to purchase from BPA for their requirements. This product is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources.

10. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make continuously available to a DSI Purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

11. Load Variance

For Core Subscription products, Load Variance is defined as the variability in monthly energy consumption within the BPA customer's system. Through the Load Variance charge under the Full and Actual Partial Service Products, the customer's billing factors will follow actual consumption. Load Variance is not applicable to Block Product purchases. For purposes of pricing and rate tests under Pre-Subscription contracts, the Load Variance charge is deemed to correspond to the PF-96 Load Shaping charge.

12. 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; and

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

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

NR is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. NR is power for which BPA’s Transmission Services may agree to provide operating reserves in accordance with the standards established by NERC, WECC, and NWPP.

13. 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 under Section 5(c) of the Northwest Power Act may purchase PF pursuant to their Residential Exchange contracts with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Purchaser’s power sales contract with BPA.

PF is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. PF is power for which BPA's Transmission Services may agree to provide operating reserves in accordance with the standards established by NERC, WECC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to Automatic Generation Control (AGC) signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance.

15. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Purchaser pursuant to the Residential Exchange Program. Under Section 5(c) of the Northwest Power Act, BPA “purchases” power from 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. The amount of power purchased and sold is 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.

16. Slice Product

The Slice product is a power sale based upon an eligible customer’s annual net firm requirements load and is shaped to BPA’s generation from the FCRPS over the year. The Slice product is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. Slice purchasers are entitled to a fixed percentage of the energy generated by the FCRPS. The Slice purchaser's percentage entitlements are set by contract. The Slice product includes both service to net requirements firm load as well as an advance sale of surplus power.

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B. Definition of Rate Schedule Terms

1. Annual Billing Cycle

The Annual Billing Cycle is the 12 months beginning with the customer’s first monthly power bill for deliveries in the first billing month starting on or after October 1.

2. Billing Demand

The Purchaser’s Billing Demand is the amount of capacity to which the demand charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand quantity for each product. The calculation of Billing Demand is described in the customer’s contract.

3. Billing Energy

The Purchaser’s Billing Energy is the amount of energy to which the energy charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Energy quantity for each product. Billing Energy is divided into HLH and LLH for this rate period.

4. California Independent System Operator (CAISO)

The FERC-regulated control area operator of the CAISO transmission grid. Its responsibilities include providing non-discriminatory access to the transmission grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The CAISO has no affiliation with any market participant.

5. California Independent System Operator (CAISO) Spinning Reserve Capacity

The portion of unloaded synchronized generating capacity, controlled by the CAISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours.

6. California Independent System Operator (CAISO) Supplemental Energy

Energy from generating units and other resources which have uncommitted capacity following finalization of the hour-ahead schedules and for which scheduling coordinators have submitted bids to the CAISO at least 30 minutes before the commencement of the settlement period.

7. Contract Demand

The Contract Demand is the maximum number of kilowatts that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

8. Contract Energy

Contract Energy is the maximum number of kilowatt-hours that the Purchaser agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Purchaser.

9. Control Area

A Control Area is the electrical (not necessarily geographical) area within which a controlling utility operating under all NERC standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and powerflow across interchange boundaries to other Control Areas.

10. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

11. Demand Entitlement

For purchases made under contracts for Core Subscription products, Demand Entitlement is the largest HLH amount of power in kilowatts that the purchaser is entitled to receive from BPA during the billing period as specified in the contract.

12. Discount Period

The end of the rate period or the customer's contract term, whichever comes first.

13. Dow Jones Mid-C (DJ Mid-C) Indexes

Average HLH (or peak) and average LLH (or off-peak) price indices for sales of electricity at delivery points along the Mid-Columbia River, as published by Dow Jones & Company, Inc.

14. Electric Power

Electric Power is electric peaking capacity (kW) and/or electric energy (kWh).

15. Energy Entitlement

For purchases made under contracts for Core Subscription products, HLH and LLH Energy Entitlement is the sum in kWh of amounts for HLH and LLH energy, respectively, that the purchaser is entitled to receive from BPA as specified in the contract.

16. Federal System

The Federal System is the generating facilities of the FCRPS, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

(a) from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

(b) which BPA may use under contract or license; or

(c) to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

17. Firm Power (PF-07R, IP-07R, NR-07R)

Firm Power is electric power (capacity and energy) that BPA will make continuously available under contracts executed pursuant to Section 5 of the Northwest Power Act.

18. Full Service Customer

A Full Service customer is one who is purchasing power from BPA through the Full Service Product.

19. Generation System Peak (GSP)

The GSP is the hour of the largest HLH output of the Federal System that occurs during the customer's billing period.

20. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period 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 matches NERC Standards in classifying six holidays as Light Load Hours.

21. Inventory Augmentation (or Inventory Solution)

BPA's action to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process.

22. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period 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 matches six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving 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 they fall on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If these days fall on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

23. Measured Demand

The Purchaser's Measured Demand is that portion of its Metered or Scheduled Demand provided by BPA to the Purchaser. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable.
The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined pursuant to the Purchaser's agreement with BPA, BPA shall adjust any abnormal Integrated Demand due to, or resulting from:

(a) emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

(b) emergencies on the Purchaser's facilities to the extent BPA determines that such facilities have been adequately maintained and prudently operated.

BPA will follow its billing process in establishing the Billing Demand should an outage cause an unusual Billing Demand quantity.

BPA will not give outage credits for demand.

24. Measured Energy

The Purchaser's Measured Energy is that portion of its Metered or Scheduled Energy that is provided by BPA to the Purchaser during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

25. 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 purchaser:

(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 Purchaser.

26. Metered Energy

The Metered Energy for a purchaser shall be the number of kWh that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Purchaser:

(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.

27. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

28. Net Billing Capacity Deficiency

A Net Billing Capacity Deficiency means that, as of the date of the Final ROD, the Administrator's forecast of purchases of power and transmission from BPA by a Net Billing Participant in any Net Billing Agreement Contact Year during the rate period exceeds 110 percent of the Administrator's forecast of the aggregate charges by Energy Northwest in the related Net Billing Agreement Contract Year.

29. NP15

The portion of the CAISO Control Area north of transmission path 15.

30. NW1 (COB)

CAISO designation for delivery at COB (Captain Jack/Malin).

31. NW3 (NOB)

CAISO designation for delivery at NOB.

32. Partial Service Customer

A Partial Service customer is any customer that is not a Full Service customer.

33. Point of Delivery (POD)

A POD is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it may be located at the change of ownership point on a transmission line.

34. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically a point of integration is located at a resource site, but it may be located at some other interconnection point to receive system power from the customer.

35. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected.

36. Points of Metering (POM)

The POM shall be those points specified in the contract at which Total Retail Load and Metered Amounts are measured.

37. Pre-Subscription Contract

A contract for service in the FY 2002 through 2006 rate period that was signed prior to January 1, 1999, is a Pre-Subscription Contract. A small number of these contracts extend through 2011.

38. Purchaser

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

39. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to a Point(s) of Delivery.

40. Retail Access

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

41. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kW is the largest of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

(a) to each system for which Scheduled 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.

Scheduled Demand is deemed delivered for the purpose of determining Billing Demand.

42. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kWh shall be the sum of the hourly demands at which electric energy is scheduled by BPA for delivery to a purchaser:

(a) for each system for which Scheduled Energy is the basis for determination of the Measured Energy; and

(b) during any billing period.

Scheduled Energy is deemed delivered for the purpose of determining Billing Energy.

43. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of items in BPA's Power Services revenue requirement, and is the basis for the Slice rate, as identified in the Power Services WP-02, WP-07, and WP-07 Supplemental Power rate cases. *See* Table 1, Slice Product Costing and True-Up Table.

44. Subscription

Subscription refers to the Power Subscription Strategy issued by BPA on December 21, 1998, which is BPA's policy for power sales for FY 2002-2011.

45. Subscription Contract

Such power sales contract effective during the period between October 1, 2001, and September 30, 2011.

46. Total Plant Load (TPL)

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period, whether the customer has chosen to serve its load with BPA power or non-Federal power.

47. Total Retail Load (TRL)

Total Retail Load (TRL) is all electric power consumption, including distribution system losses, within a utility's distribution system as measured at metering points, adjusted for unmetered loads or generation. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, TRL is called Total Plant Load.

The TRL billing determinant for the Load Variance Charge will be adjusted for any load that is designated as exempt from the charge in accordance with the customer's Power Sales Agreement.

48. Utility Distribution Company (UDC)

A company that owns and maintains the distribution facilities used to serve end-use customers.

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Appendix A
FY 2002-2011 Slice Rate Methodology

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APPENDIX A

FY 2002-2011 SLICE RATE METHODOLOGY

METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Table 1: Slice Product Costing and True-Up Table begins on page 139.

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METHODOLOGY TO CALCULATE SLICE RATE AND SLICE TRUE-UP ADJUSTMENT CHARGE

Section 1. PURPOSE

The Slice Methodology is designed as a means for providing a consistent method of calculating the rate for Slice and conducting the annual true-up for 10 years of the contract. Because there is some uncertainty regarding the calculation of the Slice rate in a rate period subsequent to the FY 2002-2006 rate period, the Slice Methodology is intended to bring some stability to the calculation of the rate. The Slice Methodology is not intended to predetermine the actual rate a Slice purchaser will pay in any rate period; rather, the Slice Methodology proposes a set of cost categories that will make up the Slice Revenue Requirement and the manner in which such costs may be trued up annually.

Section 2. TERM OF THE METHODOLOGY

After FERC approval, this methodology shall take effect on October 1, 2001, and shall terminate on the earlier of midnight September 30, 2011, or a date established by FERC.

Section 3. DEFINITIONS

Actual Slice Revenue Requirement means the use of audited actual financial data in the cost categories comprising the Slice Revenue Requirement.

Capital Expenses means depreciation expense (recovery of the investment) and net interest expense (recovery of financing costs). Depreciation standards (*e.g.*, duration of useful life) used for the recovery of capital investments under the Slice contract will be the same as those used by BPA to set power rates generally, and will not change from those used in the development of Table 1, Slice Product Costing and True-Up Table, unless BPA adopts a new depreciation study.

Contracted Loads for each rate period shall be the average of the Fiscal Year (FY) loads for such rate period contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

Forecast Loads for each rate period shall be the average of the forecast FY loads for such rate period in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

Initial Implementation Expenses means the expenses of implementing the Slice product for which BPA was reimbursed, prior to October 1, 2001, pursuant to the Master Agreement to Enable the Technical Development of a Slice of System Power Sale (Master Agreement).

Minimum Required Net Revenues means the amount by which BPA's payments to the U.S. Treasury for generation amortization and irrigation assistance exceed the total non-cash expenses in the Actual Slice Revenue Requirement.

Preexisting Multiyear Contracts means BPA's contracts for power sales, which have been executed as of June 21, 1999, with a term length that extends beyond the first year of the FY 2002-2006 rate period.

Slice Revenue Requirement means the operating and Capital Expenses and credits included in the Slice Rate which are established in the generation Revenue Requirement Study for the applicable rate periods and are subject to the criteria for inclusion of new costs or credits. The costs and credit categories included in the Slice Revenue Requirement are listed in Table 1, Slice Product Costing and True-Up Table.

Slice System Resources means the FBS resources identified in the Slice contract.

System Obligations means those operational or contractual obligations of the FBS that are identified in the Slice contract.

Section 4. METHODOLOGY

A. Slice Rate Calculation

The monthly rate for the Slice product will be calculated in the following manner:

Monthly rate for the Slice product per 1 percent of the Slice System = (Annual Average Slice Revenue Requirement / 12) /100 where the Slice Revenue Requirement is calculated as described in Section 4.B below.

For the FY 2009, the Slice Revenue Requirement will contain the costs and credits estimated in the WP-07 Supplemental Rate Case for the cost and credit categories identified in Table 1, Slice Product Costing and True-Up Table, and any other currently unidentified cost or credit, as described in Section 4.B.3. below.

B. Slice Revenue Requirement

1. Uniform Application Throughout the Rate Period

The Slice Revenue Requirement is a three-year annual average amount for the applicable rate period. The Slice Rate will remain constant during the applicable rate period.

2. Cost and Credit Categories Used to Set the Slice Revenue Requirement

The cost and credit categories used to set the Slice Revenue Requirement and the Actual Slice Revenue Requirement shall be those defined in the generation Revenue Requirement Study for the 2002 Final Power Rate Proposal and listed in Table 1, Slice Product Costing and True-Up Table.

For FY 2002 only, the total of all Initial Implementation Expenses that BPA received under the Master Agreements shall be included in the Actual Slice Revenue Requirement.

3. Inclusion of New Costs or Credits

Power Services costs or credits not otherwise specifically dealt with in the Slice Revenue Requirement, or excluded there from as specified in Section 4.B.4. below, may be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement, if and to the extent that:

Such Power Services costs or credits could be properly includable in Power Services' wholesale power rates; and either

a. Such Power Services costs or credits are: (1) incurred by Power Services to provide service to customers other than Slice purchasers; and (2) incurred to provide service to or otherwise benefit Slice purchasers;

OR

b. Such Power Services costs or credits are not incurred to provide service to customers other than Slice purchasers, nor to provide service to or otherwise benefit Slice purchasers.

4. Costs Excluded from the Slice Revenue Requirement

Excluded costs include, but are not limited to the following:

- All transmission costs (other than those associated with the transmission of System Obligations and GTAs);
- All power purchase costs (with the exception of net Inventory Solution costs);
- All PNRR and hedging costs, with the exception of those hedging costs incurred to implement the forecast Inventory Solution; and
- All costs not permitted to be included in the Slice Revenue Requirement as specified by Section 4.B.3. above.

5. Credits

a. Systemwide Credits

Systemwide credits are any monetary credits that Power Services forecasts to receive that are associated with the costs identified in the Slice Revenue Requirement. Systemwide credits shall be included in both the Slice

Revenue Requirement and the Actual Slice Revenue Requirement as a credit. The credits include, but are not limited to:

- Credits from the U.S. Treasury for Power Services' settlement payment to the Colville Tribe;
- Credits from the U.S. Treasury for Section 4(h)(10)(c) of the Northwest Power Act;
- Credits from the U.S. Treasury for the FCCF; and
- Revenues BPA receives for meeting System Obligations (including revenues received for Congestion Management or PNCA transactions).

b. Transmission Surcharge

As provided for under separate rate and contract, BPA's Transmission Services may impose a transmission surcharge on the Slice purchaser's use of the BPA transmission system. Any revenues received by Transmission Services pursuant to such surcharge will be credited to Power Services' total Actual Slice Revenue Requirement, and will be reflected in the Slice purchaser's True-Up Adjustment. Repayment of such funds by the Power Services to Transmission Services, if any, shall be included in the Actual Slice Revenue Requirement.

c. Purchaser-Specific Credits and Other Contract Related Charges

All Slice purchaser-specific credits and other Slice purchaser-specific charges resulting from the implementation of the Slice contract shall be applied as an adjustment to the Slice True-Up Adjustment Charge for each specific Slice purchaser. The adjustment for credits and charges associated with the implementation of the Slice contract will be defined in the Slice contract.

6. Inapplicability of the Cost Recovery Adjustment Clause (CRAC), the National Marine Fisheries Service, Federal Columbia River Power System, Biological Opinion Adjustment (NFB Adjustment), the Emergency NFB Surcharge, the Targeted Adjustment Clause (TAC), and the Dividend Distribution Clause (DDC)

Neither the Slice Rate nor the Slice True-Up Adjustment Charge paid by Slice purchasers will be subject to the CRAC, the NFB Adjustment, the Emergency NFB Surcharge, the TAC, or the DDC identified in the WP-07 GRSPs or any successor thereto.

7. Net Cost of the Inventory Solution

BPA has forecast firm energy purchases that supplement the capability of FBS Resources (Inventory Solution) to meet the forecast loads. The cost of the Inventory Solution shall be included in both the Slice Revenue Requirement and the Actual Slice Revenue Requirement on a net cost basis. The forecast net cost of the Inventory Solution (NCIS) shall be calculated as: (1) the total expenses for the Inventory Solution; less (2) the total revenues for the sale of such power; both as projected by BPA. Since Slice purchasers bear the responsibility for their proportionate share of any loss of FBS resources or capability thereof, the Inventory Solution will not include such replacements. The forecast net cost of the Inventory Solution to be included in the Slice Revenue Requirement for FY 2009 is identified in Table 1.

C. Slice True-Up Adjustment Charge

The Slice True-Up Adjustment Charge is a monthly charge applied to the Slice product that is expressed in terms of dollars per percent Slice selected. The Slice True-Up Adjustment Charge consists of the Annual Slice True-Up Adjustment that is calculated once each fiscal year and is applied to specific months of the fiscal year. The Slice True-Up Adjustment Charge for each month shall be calculated in the following manner:

$STUAC_M = ASTU_M$

Where:

$STUAC_M$ is the Slice True-Up Adjustment Charge for month M of the rate period.

$ASTU_M$ is the portion of the Annual Slice True-Up Adjustment applicable for month M.

1. Annual Slice True-Up Adjustment

The Annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as independently audited actual financial data are available. As necessary, the Actual Slice Revenue Requirement shall include a Minimum Required Net Revenues component to ensure coverage of annual cash requirements. The Annual Slice True-Up Adjustment shall be calculated to be the annual average Slice Revenue Requirement for the applicable rate period subtracted from the Actual Slice Revenue Requirement for such FY as shown in Table 1. The Annual Slice True-Up Adjustment shall be applied either as a one month credit (if the adjustment is negative) or as a three-month charge (if the adjustment is positive, and spread equally across the three months) following the month the Annual Slice True-Up Adjustment is calculated.

Table 1
Slice Product Costing and True-Up Table

($000s)

		Audited Actual Data	FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		$ 263,669	$ 188,688	$ 293,700
5	BUREAU OF RECLAMATION		$ 71,654	$ 74,760	$ 82,100
6	CORPS OF ENGINEERS		$ 161,519	$ 165,742	$ 179,500
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 24,932	$ 25,314	$ 31,522
8	**Sub-Total**		**$ 521,774**	**$ 454,504**	**$ 586,822**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		$ 16,968	$ 17,354	$ 20,909
11	SPOKANE GENERATION SETTLEMENT		$ -	$ -	$ -
12	**Sub-Total**		**$ 16,968**	**$ 17,354**	**$ 20,909**
13	**Non-Operating Generation**				
14	TROJAN DECOMMISSIONING		$ 5,400	$ 4,700	$ 2,500
15	WNP-1&3 DECOMMISSIONING		$ 200	$ 200	$ 400
16	**Sub-Total**		**$ 5,600**	**$ 4,900**	**$ 2,900**
17	**Contracted Power Purchases**				
18	PNCA HEADWATER BENEFIT		$ 1,714	$ 1,714	$ 1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)				
20	DSI MONETIZED POWER SALE		$ 59,000	$ 59,000	$ 54,999
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**$ 60,714**	**$ 60,714**	**$ 56,713**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**$ 6,762**	**$ 6,811**	**$ 1,107**
27	IOU RESIDENTIAL EXCHANGE		**$ 301,000**	**$ 301,000**	**$ 251,161**
28	**Renewable Generation (expenses related to reinvestment removed)**		**$ 30,289**	**$ 34,719**	**$ 41,050**
29	**Generation Conservation**				
30	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000	$ 5,812
31	ENERGY EFFICIENCY DEVELOPMENT		$ 12,885	$ 12,908	$ 22,000
32	ENERGY WEB		$ 1,000	$ 1,000	$ 7,000
33	**LEGACY (Until 11/1/03 this was included with line 72)**		$ 3,728	$ 2,638	$ 2,114
34	MARKET TRANSFORMATION		$ 10,000	$ 10,000	$ 10,000
35	TECHNOLOGY LEADERSHIP		$ 1,300	$ 1,300	$ 1,600
36	INFRASTRUCTURE SUPPORT AND EVALUATION		$ 1,000	$ 1,000	
37	BI-LATERAL CONTRACT ACTIVITY		$ 1,000	$ 1,000	
38	**Sub-Total**		**$ 35,913**	**$ 34,846**	**$ 48,526**
39	CONSERVATION RATE CREDIT		$ 36,000	$ 36,000	$ 32,000
40	**Power System Generation Sub-Total**		**$ 1,015,019**	**$ 950,848**	**$ 1,041,188**
41					
42	**PBL Transmission Acquisition and Ancillary Services**				
43	**PBL Transmission Acquisition and Ancillary Services**				
44	PBL - TRANSMISSION & ANCILLARY SERVICES				
45	Canadian Entitlement Agreement Transmission Expenses		$ 24,806	$ 25,550	$ 27,000
46	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,775	$ 1,825	$ 1,000
47	3RD PARTY GTA WHEELING		$ 47,000	$ 47,000	$ 50,370
48	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				$ -
49	RESERVE & OTHER SERVICES		$ 8,462	$ 8,462	$ 6,800
50	TELEMETERING/EQUIP REPLACEMT		$ 200	$ 200	$ 50
51	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**$ 82,243**	**$ 83,037**	**$ 85,220**
52					
53	**Power Non-Generation Operations**				
54	**PBL System Operations**				
55	EFFICIENCIES PROGRAM (omit TMS expenses)		$ -	$ -	$ -
56	INFORMATION TECHNOLOGY		$ -	$ -	$ 5,423
57	GENERATION PROJECT COORDINATION		$ 5,637	$ 5,738	$ 7,648
58	SLICE IMPLEMENTATION (omit - calculated separately)				
59	**Sub-Total**		**$ 5,637**	**$ 5,738**	**$ 13,071**
60	**PBL Scheduling**				
61	OPERATIONS SCHEDULING		$ 8,758	$ 9,051	$ 9,571
62	OPERATIONS PLANNING		$ 5,202	$ 5,358	$ 5,969
63	**Sub-Total**		**$ 13,960**	**$ 14,409**	**$ 15,540**
64	**PBL Marketing and Business Support**				
65	SALES & SUPPORT		$ 15,884	$ 16,278	$ 18,988
66	Contractual exclusion		$ (5,360)	$ (5,360)	$ (5,360)
67	Implementation Expense Exclusions - Add back				
68	PUBLIC COMMUNICATION & TRIBAL LIAISON				
69	STRATEGY, FINANCE & RISK MGMT		$ 10,965	$ 11,359	$ 14,820
70	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 845	$ 840	$ 3,123
71	CONSERVATION SUPPORT (EE staff costs)		$ 6,441	$ 6,692	$ 7,996
72	**Sub-Total**		**$ 28,776**	**$ 29,808**	**$ 39,567**
73	**Power Non-Generation Operations Sub-Total**		**$ 48,372**	**$ 49,955**	**$ 68,178**
74					
75	**Fish and Wildlife/USF&W/Planning Council**				
76	**BPA Fish and Wildlife (includes F&W Shared Services)**				
77	FISH & WILDLIFE		$ 143,000	$ 143,000	$ 199,998
78	F&W HIGH PRIORITY ACTION PROJECTS				
79	**Sub-Total**		**$ 143,000**	**$ 143,000**	**$ 199,998**
80	**PBL-USF&W Lower Snake Hatcheries**				
81	USF&W LOWER SNAKE HATCHERIES		$ 18,600	$ 19,500	$ 19,690
82	**PBL - Planning Council**				
83	PLANNING COUNCIL		$ 9,085	$ 9,276	$ 9,450
84	**PBL - ENVIRONMENTAL REQUIREMENTS**				
85	ENVIRONMENTAL REQUIREMENTS		$ 500	$ 500	$ 300
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 171,185**	**$ 172,276**	**$ 229,438**

Table 1, continued
Slice Product Costing and True-Up Table

87					
88	**BPA Internal Support**				
89	**CSRS/FERS**				
90	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$ 10,550	$ 9,000	$ 15,277	
91	**Corporate Support - G&A (excludes direct project support)**				
92	CORPORATE G&A	$ 50,247	$ 51,753	$ 44,994	
93	**TBL Supply Chain - Shared Services**	$ 368	$ 374		
94	**General and Administrative/Shared Services Sub-Total**	**$ 61,165**	**$ 61,127**	**$ 60,271**	
95					
96	**Bad Debt Expense**				
97	**Other Income, Expenses, Adjustments**	**$ 1,800**	**$ 1,800**	$ -	
98	**Non-Federal Debt Service**				
99	**Energy Northwest Debt Service**				
100	COLUMBIA GENERATING STATION DEBT SVC	$ 195,690	$ 217,856	$ 224,801	
101	WNP-1 DEBT SVC	$ 147,941	$ 165,916	$ 169,509	
102	WNP-3 DEBT SVC	$ 151,724	$ 160,092	$ 150,983	
103	EN RETIRED DEBT				
104	EN LIBOR INTEREST RATE SWAP				
105	**Sub-Total**	**$ 495,355**	**$ 543,864**	**$ 545,293**	
106	**Non-Energy Northwest Debt Service**				
107	TROJAN DEBT SVC	$ 8,605	$ 7,888	$ -	
108	CONSERVATION DEBT SVC	$ 5,203	$ 5,198	$ 5,188	
109	COWLITZ FALLS DEBT SVC	$ 11,619	$ 11,583	$ 11,571	
110	WASCO DEBT SVC	$ -	$ 1,664	$ 2,168	
111	**Sub-Total**	**$ 25,427**	**$ 26,333**	**$ 18,927**	
112	**Non-Federal Debt Service Sub-Total**				
113	Depreciation (excl. TMS)	$ 118,058	$ 121,829	$ 118,832	
114	Amortization (excludes ConAug amortization)	$ 55,567	$ 60,241	$ 56,412	
115	**Total Operating Expenses**	**$ 2,074,191**	**$ 2,071,310**	**$ 2,223,759**	
116					
117	**Other Expenses**				
118	Net Interest Expense	$ 163,080	$ 173,193	$ 160,845	
119	LDD	$ 22,289	$ 22,612	$ 25,219	
120	Irrigation Rate Mitigation Costs	$ 10,000	$ 10,000	$ 12,000	
121	**Sub-Total**	**$ 195,369**	**$ 205,805**	**$ 198,064**	
122	**Total Expenses**	**$ 2,269,560**	**$ 2,277,115**	**$ 2,421,823**	
123					
124	**Revenue Credits**				
125	Ancillary and Reserve Service Revs. Total	$ 73,131	$ 61,970	$ 79,306	
126	Downstream Benefits and Pumping Power	$ 8,921	$ 8,921	$ 8,921	
127	4(h)(10)(c)	$ 84,707	$ 84,927	$ 88,480	
128	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 4,600	
129	FCCF				
130	Energy Efficiency Revenues	$ 12,885	$ 12,908	$ 22,000	
131	Miscellaneous	$ 3,420	$ 3,420	$ 3,420	
132	**Total Revenue Credits**	**$ 187,664**	**$ 176,746**	**$ 206,727**	
133					
134	**Augmentation Costs**				
135	**IOU Reduction of Risk Discount (includes interest)**	$ 23,024	$ 23,024		
136	(Net augmentation power costs are not subject to True-Up)				
137	**Forecasted Gross Augmentation Costs**				
138	Residual augmentation cost	$ 49,005			
139	Other augmentation cost	$ 97,062	$ 95,001	$ 161,122	
140	Minus revenues	$ 67,993	$ 42,972	$ 73,667	
141	**Net Cost of Augmentation**	**$ 101,098**	**$ 75,053**	**$ 87,455**	
142					
143					
144	**Minimum Required Net Revenue calculation**				
145	Principal Payment of Fed Debt for Power	$ 202,331	$ 172,483	$ 103,065	
146	Irrigation assistance	$ -	$ 2,950	$ 7,279	
147	Depreciation	$ 118,058	$ 121,829	$ 118,832	
148	Amortization	$ 71,658	$ 76,332	$ 69,748	
149	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ (45,937)	
150	Bond Premium Amortization	$ 613	$ 613	$ 185	
151	Principal Payment of Fed Debt exceeds non cash expenses	$ 57,939	$ 22,596	$ (32,484)	
152	Minimum Required Net Revenues	**$ 57,939**	**$ 22,596**	$ -	
153					**3-Year Total Rev Reqt**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**$ 2,240,934**	**$ 2,198,018**	**$ 2,302,550**	**$ 6,741,502**
155					
156	SLICE TRUE-UP ADJUSTMENT CALCULATION				
157	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Rate Case	**$ 2,252,465**			
158	FY 2007-2009 Average Slice Revenue Requirement determined in WP-07 Supplemental Rate Cas	**$ 2,247,167**			
159	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)				
160	AMOUNT BILLED (22.6278 percent)				
161	Slice Implementation Expenses (not incl. in base rate)				
162	TRUE UP ADJUSTMENT				
163					
164					
165	**SLICE RATE CALCULATION ($)**				
166	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 187,263,943**
167	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**				**$ 1,872,639**
168					
169	**ANNUAL BASE SLICE REVENUES**				**$ 508,484,525**
170	**Annual Slice Implementation Expenses**				**$ 2,486,000**
171	**TOTAL ANNUAL SLICE REVENUES**				**$ 510,970,525**

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Appendix B

Customer Lookback Credit in FY 2009

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Customer Lookback Credit in FY 2009

Section 1. Purpose

The Customer Lookback Credit in FY 2009 is a credit on a customer's bill that reflects the return of a portion of overcharges for the Residential Exchange Program settlement agreements incurred by customers who paid the PF-02 rate in FY 2002-2006. The amount of the credit is determined in each rate case until the total Lookback Amount is extinguished. The Annual FY 09 Lookback Credit Amount was determined in the 2007 Supplemental Wholesale Power Rate Case.

Section 2. Terms of the Customer Lookback Credit

The Customer Lookback Credit applies to customers that purchased power from BPA at the PF-02 Priority Firm rates under their Subscription contracts.

Credits shall appear on monthly power bills beginning with the month that the rates established in the 2007 Supplemental Wholesale Power Rate Case take effect. The FY 2009 credit will be provided in 12 equal monthly amounts that total the annual amounts.

The documentation of the amount of the Annual FY 09 Lookback Credit Amount to be returned in FY 2009 can be found in the FY 2002-2008 Lookback Study, Chapter 15. *See* FY 2002-2008 Lookback Study, WP-07-FS-BPA-08.

Section 3. Definitions

<u>Annual FY 09 Lookback Credit Amount</u> is the portion of the REP settlement agreement overcharges incurred by customers who paid the PF-02 rates that will be returned to Slice and Non-Slice customers in FY 2009.

<u>Non-Slice Annual FY 09 Lookback Credit Amount</u> is the portion of the Annual FY 09 Lookback Credit Amount that is due to customers that paid the PF-02 non-Slice rates. It is equal to 77.3722 percent of the Annual Lookback Amount.

<u>Non-Slice PF-02 Revenue Share</u> is the percentage used to allocate the Non-Slice Annual FY 09 Lookback Credit Amount to each customer that paid the non-Slice PF-02 rates. It is equal to the ratio of each customer's non-Slice PF-02 revenues, including revenues from block purchases of the Slice customers, divided by the total non-Slice revenues at the PF-02 rate collected from all non-Slice customers, including revenues from block purchases, in FY 2002-2006.

<u>Non-Slice Monthly FY 09 Lookback Credit Amount</u> is the monthly credit due to each non-Slice customer in FY 2009 that paid the non-Slice PF-02 rates. It is equal to the Non-Slice Annual FY 09 Lookback Credit Amount times the Non-Slice PF-02 Revenue Share divided by 12.

Slice Annual FY 09 Lookback Credit Amount is the portion of the Annual FY 09 Lookback Credit Amount that is due to customers that paid the PF-02 Slice rate. It is equal to 22.6278 percent of the Annual FY 09 Lookback Credit Amount.

Slice % Share is the percentage used to allocate the Slice Annual FY 09 Lookback Credit Amount to each Slice customer. It is equal to each Slice customer's Slice percentage divided by the sum of all customers' Slice percentages (22.6278 percent).

Slice Monthly FY09 Lookback Credit Amount is the monthly credit due to each Slice customer in FY 2009 that paid the Slice PF-02 rate. It is equal to the Slice Annual FY 09 Lookback Credit Amount times the Slice % Share divided by 12.

Section 4. Customer Lookback Credit

Customer Lookback Credit

Annual FY 09 Lookback Credit Amount =	**$154,477,000**
Slice Annual FY 09 Lookback Credit Amount	$34,954,747
Non-Slice Annual FY 09 Lookback Credit Amount	$119,522,253

	Customer Name	**Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY 09 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY09 Lookback Credit Amount**
10055	Albion, City of	0.0000%	$-	0.00000%	$-
10005	Alder Mutual	0.0107%	$1,070	0.00000%	$-
10057	Ashland, City of	0.5462%	$54,406	0.00000%	$-
10015	Asotin County PUD #1	0.0000%	$-	0.00000%	$-
10059	Bandon, City of	0.1878%	$18,705	0.00000%	$-
10024	Benton County PUD #1	1.3514%	$134,602	7.79616%	$227,094
10025	Benton REA	1.2380%	$123,311	0.00000%	$-
10027	Big Bend Elec Coop	0.6159%	$61,343	0.00000%	$-
10028	Big Horn County Electric Coop.	0.0000%	$-	0.00000%	$-
10029	Blachly Lane Elec Coop	0.0000%	$-	0.29066%	$8,467
10061	Blaine, City of	0.2046%	$20,378	0.00000%	$-
10062	Bonners Ferry, City of	0.1541%	$15,344	0.00000%	$-
10064	Burley, City of	0.3564%	$35,496	0.00000%	$-
10044	Canby, City of	0.4964%	$49,440	0.00000%	$-
10065	Cascade Locks, City of	0.0606%	$6,032	0.00000%	$-
10046	Central Electric Coop	0.0000%	$-	1.01490%	$29,563
10047	Central Lincoln PUD	1.6349%	$162,842	0.00000%	$-
10048	Central Montana Electric Power Coop	0.0000%	$-	0.00000%	$-
10066	Centralia, City of	0.5552%	$55,296	0.00000%	$-
10067	Cheney, City of	0.3672%	$36,575	0.00000%	$-
10068	Chewelah, City of	0.0000%	$-	0.00000%	$-
10101	Clallam County PUD #1	1.7593%	$175,234	0.00000%	$-
10103	Clark County PUD #1	8.0133%	$798,136	0.00000%	$-
10105	Clatskanie PUD	0.8255%	$82,221	4.31107%	$125,577
10106	Clearwater Power	0.0000%	$-	0.36340%	$10,586
10109	Columbia Basin Elec Coop	0.0000%	$-	0.00000%	$-
10111	Columbia Power Coop	0.0000%	$-	0.00000%	$-
10113	Columbia REA	0.0000%	$-	0.00000%	$-
10112	Columbia River PUD	0.8976%	$89,399	0.00000%	$-
10116	Consolidated Irrigation District #19	0.0062%	$615	0.00000%	$-
10118	Consumers Power	0.0000%	$-	0.64160%	$18,689
10121	Coos Curry Elec Coop	0.0000%	$-	0.58645%	$17,083
10378	Coulee Dam, City of	0.0000%	$-	0.00000%	$-
10123	Cowlitz County PUD #1	11.5368%	$1,149,087	0.00000%	$-
10070	Declo, City of	0.0000%	$-	0.00000%	$-
10136	Douglas Electric Cooperative	0.0000%	$-	0.28805%	$8,391

Customer Lookback Credit

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	Customer Name	**Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY 09 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY09 Lookback Credit Amount**
10071	Drain, City of	0.0645%	$6,427	0.00000%	$-
10142	East End Mutual Electric	0.0000%	$-	0.00000%	$-
10144	Eatonville, Town of	0.0785%	$7,822	0.00000%	$-
10072	Ellensburg, City of	0.5924%	$59,003	0.00000%	$-
10156	Elmhurst Mutual P & L	0.0000%	$-	0.00000%	$-
10157	Emerald County PUD	1.2731%	$126,807	0.00000%	$-
10158	Energy Northwest	0.0690%	$6,875	0.00000%	$-
10170	Eugene Water & Electric Board	1.8894%	$188,188	10.75138%	$313,176
10172	Fairchild AFB	0.2045%	$20,368	0.00000%	$-
10173	Fall River Elec Coop	0.0000%	$-	0.32447%	$9,451
10174	Farmers Electric Company	0.0000%	$-	0.00000%	$-
10177	Ferry County PUD #1	0.2293%	$22,838	0.00000%	$-
10179	Flathead Elec Coop	2.0560%	$204,780	0.00000%	$-
10074	Forest Grove, City of	0.5719%	$56,965	0.00000%	$-
10183	Franklin County PUD #1	0.5806%	$57,828	3.46963%	$101,067
10186	Glacier Elec Coop	0.0000%	$-	0.00000%	$-
10190	Grant County PUD #2	3.8794%	$386,399	0.00000%	$-
10191	Grays Harbor PUD #1	0.9797%	$97,580	5.16223%	$150,370
10197	Harney Elec Coop	0.3094%	$30,822	0.00000%	$-
10597	Hermiston, City of	0.3388%	$33,746	0.00000%	$-
10076	Heyburn, City of	0.1708%	$17,012	0.00000%	$-
10202	Hood River Elec Coop	0.3036%	$30,236	0.00000%	$-
10203	Idaho County L & P	0.1319%	$13,135	0.00000%	$-
10204	Idaho Falls Power	0.5748%	$57,253	3.06305%	$89,223
10209	Inland P & L	0.0000%	$-	0.00000%	$-
10230	Kittitas County PUD #1	0.1625%	$16,185	0.00000%	$-
10231	Klickitat County PUD #1	0.7414%	$73,846	0.00000%	$-
10234	Kootenai Electric Coop	0.0000%	$-	0.00000%	$-
10235	Lakeview L & P (WA)	0.8854%	$88,190	0.00000%	$-
10236	Lane County Elec Coop	0.0000%	$-	0.41825%	$12,183
10237	Lewis County PUD #1	2.4361%	$242,638	0.00000%	$-
10239	Lincoln Elec Coop (MT)	0.0000%	$-	0.00000%	$-
10242	Lost River Elec Coop	0.0000%	$-	0.10854%	$3,162
10244	Lower Valley Energy	0.0000%	$-	0.00000%	$-
10246	Mason County PUD #1	0.1761%	$17,537	0.00000%	$-
10247	Mason County PUD #3	1.8392%	$183,188	0.00000%	$-
10078	McCleary, City of	0.1203%	$11,978	0.00000%	$-
10079	McMinnville, City of	2.0081%	$200,012	0.00000%	$-

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	Customer Name	**Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY 09 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY09 Lookback Credit Amount**
10256	Midstate Elec Coop	0.9710%	$96,712	0.00000%	$-
10081	Milton Freewater, City of	0.2601%	$25,910	0.00000%	$-
10080	Milton, City of	0.1816%	$18,083	0.00000%	$-
10082	Minidoka, City of	0.0000%	$-	0.00000%	$-
10258	Mission Valley	0.0000%	$-	0.00000%	$-
10259	Missoula Elec Coop	0.0000%	$-	0.00000%	$-
10260	Modern Elec Coop	0.0000%	$-	0.00000%	$-
10083	Monmouth, City of	0.2015%	$20,067	0.00000%	$-
10273	Nespelem Valley Elec Coop	0.1196%	$11,909	0.00000%	$-
10278	Northern Lights	0.0000%	$-	0.28363%	$8,262
10279	Northern Wasco County PUD	0.5733%	$57,102	0.00000%	$-
10284	Ohop Mutual Light Company	0.0000%	$-	0.00000%	$-
10285	Okanogan County Elec Coop	0.0000%	$-	0.08052%	$2,345
10286	Okanogan County PUD #1	0.3819%	$38,038	2.18802%	$63,735
10288	Orcas P & L	0.0000%	$-	0.00000%	$-
10291	Oregon Trail Coop	1.8121%	$180,492	0.00000%	$-
10294	Pacific County PUD #2	0.8903%	$88,677	0.00000%	$-
10304	Parkland L & W	0.0000%	$-	0.00000%	$-
10306	Pend Oreille County PUD #1	0.2442%	$24,324	1.68775%	$49,162
10307	Peninsula Light Company	1.6367%	$163,019	0.00000%	$-
10086	Plummer, City of	0.0955%	$9,514	0.00000%	$-
10298	PNGC	3.0958%	$308,352	12.37416%	$360,446
10087	Port Angeles, City of	1.7490%	$174,200	0.00000%	$-
10706	Port of Seattle	0.0000%	$-	0.00000%	$-
10326	Puget Sound Naval Shipyard (Bremerton)	0.7338%	$73,089	0.00000%	$-
10331	Raft River Elec Coop	0.0000%	$-	0.17448%	$5,082
10333	Ravalli County Elec Coop	0.0000%	$-	0.00000%	$-
10089	Richland, City of	2.1095%	$210,110	0.00000%	$-
10338	Riverside Elec Company	0.0000%	$-	0.00000%	$-
10091	Rupert, City of	0.2466%	$24,561	0.00000%	$-
10342	Salem Elec Coop	1.1577%	$115,312	0.00000%	$-
10343	Salmon River Elec Coop	0.0000%	$-	0.34683%	$10,103
10349	Seattle City Light	3.4471%	$343,339	20.62772%	$600,864
10352	Skamania County PUD #1	0.3734%	$37,189	0.00000%	$-
10354	Snohomish County PUD #1	8.3965%	$836,308	22.06534%	$642,740
10094	Soda Springs, City of	0.0000%	$-	0.00000%	$-
11342	Southern MT G&T	0.0000%	$-	0.00000%	$-
10360	South Side Electric	0.0000%	$-	0.00000%	$-

Customer Lookback Credit

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	Slice Annual FY 09 Lookback Credit Amount	$34,954,747
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	Customer Name	**Non-Slice PF-02 Revenue Share**	**Non-Slice Monthly FY 09 Lookback Credit Amount**	**Slice % Share**	**Slice Monthly FY09 Lookback Credit Amount**
10363	Springfield Utility Board	1.6589%	$165,231	0.00000%	$-
10379	Steilacoom, Town of	0.1201%	$11,957	0.00000%	$-
10095	Sumas, City of	0.0793%	$7,896	0.00000%	$-
10369	Surprise Valley Elec Coop	0.2767%	$27,558	0.00000%	$-
10370	Tacoma Public Utilities	10.0716%	$1,003,155	0.00000%	$-
10371	Tanner Elec Coop	0.2008%	$20,001	0.00000%	$-
10376	Tillamook PUD #1	0.9720%	$96,814	0.00000%	$-
10097	Troy, City of	0.0000%	$-	0.00000%	$-
10406	U.S. DOE Albany	0.0112%	$1,112	0.00000%	$-
10408	U.S. Naval Station, Everett (Jim Creek)	0.0365%	$3,631	0.00000%	$-
10409	U.S. Naval Submarine Base, Bangor	0.5124%	$51,035	0.00000%	$-
10388	Umatilla Elec Coop	0.0000%	$-	1.44729%	$42,158
10482	Umpqua Indian Utility Cooperative	0.0530%	$5,284	0.00000%	$-
10391	United Electric Coop	0.4876%	$48,564	0.00000%	$-
10399	USBIA Wapato	0.0171%	$1,707	0.00000%	$-
10426	USDOE-Richland	0.6536%	$65,101	0.00000%	$-
10434	Vera Irrigation District	0.6442%	$64,161	0.00000%	$-
10436	Vigilante Elec Coop	0.0000%	$-	0.00000%	$-
10440	Wahkiakum County PUD #1	0.1099%	$10,945	0.00000%	$-
10442	Wasco Elec Coop	0.0000%	$-	0.00000%	$-
11680	Weiser, City of	0.0000%	$-	0.00000%	$-
10446	Wells Rural Electric Company	1.3147%	$130,944	0.00000%	$-
10448	West Oregon Elec Coop	0.0000%	$-	0.13444%	$3,916
10451	Whatcom County PUD #1	0.6089%	$60,647	0.00000%	$-
10502	Yakama Power	0.0096%	$958	0.00000%	$-
	Total	100.000%	$9,960,198	100.000%	$2,912,895

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