2002 INITIAL POWER RATE PROPOSAL

WHOLESALE POWER RATE SCHEDULES

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August 1999

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2002 Initial Power Rate Proposal

Wholesale Power Rate Schedules

WP-02-E-BPA-07
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2002 WHOLESALE POWER RATES
TABLE OF CONTENTS

Commonly Used Acronyms ii

Power Rate Schedules Starting FY 2002 1

General Rate Schedule Provisions Starting FY 2002..... 73

New 1996 General Rate Schedule Provisions 126

COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
ASC	Average System Cost
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
Btu	British Thermal Unit
California PX	California Power Exchange
C&R Discount	Conservation and Renewables Discount
CBP	Columbia Basin Project
Cfs	cubic feet per second
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EIA	Energy Information Administration
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth Northwest Conservation and Electric Power Plan
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis

FY	Fiscal Year (Oct-Sep)
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLH	Heavy Load Hour
IJC	International Joint Commission
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour
L/R Balance	Load/Resource Balance
MAF	Million Acre Feet
m/kWh	Mills per kilowatthour
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOP	Minimum Operating Pool
MW	Megawatt (1 million watts)
MWh	Megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
NR	New Resource Firm Power (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
O&M	Operation and Maintenance
OY	Operating Year (Aug-Jul)

PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNUCC	Pacific Northwest Utilities Conference Committee
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
PSW	Pacific Southwest
PURPA	Public Utilities Regulatory Policies Act
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
Reclamation	Bureau of Reclamation
RFP	Request for Proposal
RISKMOD	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
REP	Residential Exchange Program
SCCT	Single-Cycle Combustion Turbine
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
TRL	Total Retail Load
UDC	Utility Distribution Company
USFWS	U.S. Fish and Wildlife Service
URC	Upper Rule Curve
WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WY	Watt-Year
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool

**BPA'S 2002
POWER RATE SCHEDULES**

INDEX
2002 POWER RATE SCHEDULES

PF-02	Priority Firm Power Rate	3
RL-02	Residential Load Firm Power Rate	30
NR-02	New Resource Firm Power Rate	36
IP-02	Industrial Firm Power Rate	57
NF-02	Nonfirm Power Rate	66

SCHEDULE PF-02 PRIORITY FIRM POWER

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power or capacity to be used within the Pacific Northwest. Priority Firm 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, 2001, and are available for purchase under requirements Firm Power sales contracts for a three or five-year period. The Slice Product is only available for public bodies and cooperatives. Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to the Residential Exchange Program. Utilities participating in settlement of the Residential Exchange Program may purchase Priority Firm Power pursuant to their Subscription settlement agreement. Rates under contracts that contain charges that escalate based on BPA's Priority Firm Power rates shall be based on the five-year rates listed in this rate schedule in addition to applicable transmission charges.

Sales under the PF Exchange Subscription rate will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate "Benefits of the Federal Columbia River Power System (FCRPS)" to describe the amount of benefits each consumer receives. Only the block product is available under this rate schedule.

This rate schedule supersedes the PF-96 rate schedule, which went into effect October 1, 1996. Sales under the PF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). Products available under this rate schedule are defined in the 2002 GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

SECTION II. RATES TABLES

The rates in this section apply to PF products. The PF Exchange Program rates and the PF Exchange Subscription rates are shown in Section III.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing Firm Power for three or five years.
These rates are also used to implement the Pre-Subscription Contracts.

1.2 Rate Table

<i>Applicable Months</i>	<i>Rate</i>
January	\$2.14/kW-mo
February	\$2.06/kW-mo
March	\$1.96/kW-mo
April	\$1.37/kW-mo
May	\$1.32/kW-mo
June	\$1.69/kW-mo
July	\$2.12/kW-mo
August	\$2.44/kW-mo
September	\$2.28/kW-mo
October	\$1.90/kW-mo
November	\$2.31/kW-mo
December	\$2.40/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to customers purchasing power in the first three years of the rate period.

1.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	19.06 mills/kWh	13.45 mills/kWh
February	17.95 mills/kWh	12.84 mills/kWh
March	17.18 mills/kWh	12.09 mills/kWh
April	11.64 mills/kWh	8.55 mills/kWh
May	11.21 mills/kWh	7.02 mills/kWh
June	14.51 mills/kWh	8.61 mills/kWh
July	18.85 mills/kWh	15.60 mills/kWh
August	29.24 mills/kWh	19.23 mills/kWh
September	20.09 mills/kWh	19.40 mills/kWh
October	16.68 mills/kWh	13.35 mills/kWh
November	20.56 mills/kWh	17.77 mills/kWh
December	21.40 mills/kWh	17.67 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for customers purchasing for all five years of the rate period.

2.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	20.56 mills/kWh	14.95 mills/kWh
February	19.45 mills/kWh	14.34 mills/kWh
March	18.68 mills/kWh	13.59 mills/kWh
April	13.14 mills/kWh	10.05 mills/kWh
May	12.71 mills/kWh	8.52 mills/kWh
June	16.01 mills/kWh	10.11 mills/kWh
July	20.35 mills/kWh	17.10 mills/kWh
August	30.74 mills/kWh	20.73 mills/kWh
September	21.59 mills/kWh	20.90 mills/kWh
October	18.18 mills/kWh	14.85 mills/kWh
November	22.06 mills/kWh	19.27 mills/kWh
December	22.90 mills/kWh	19.17 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates are used to implement the Pre-Subscription Contracts. These rates are also available to customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	19.66 mills/kWh	14.05 mills/kWh
February	18.55 mills/kWh	13.44 mills/kWh
March	17.78 mills/kWh	12.69 mills/kWh
April	12.24 mills/kWh	9.15 mills/kWh
May	11.81 mills/kWh	7.62 mills/kWh
June	15.11 mills/kWh	9.21 mills/kWh
July	19.45 mills/kWh	16.20 mills/kWh
August	29.84 mills/kWh	19.83 mills/kWh
September	20.69 mills/kWh	20.00 mills/kWh
October	17.28 mills/kWh	13.95 mills/kWh
November	21.16 mills/kWh	18.37 mills/kWh
December	22.00 mills/kWh	18.27 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV below. The rate for Load Variance is 0.8 mills/kWh.

D. SLICE RATE

The monthly rate for the Slice Product is \$1,381,390 per 1 percent of the Slice System.

SECTION III. PF EXCHANGE RATE TABLES

The rates in this section apply to sales under the Residential Exchange Program and the Subscription settlements of the Residential Exchange Program.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program and to customers purchasing power for all five years of the rate period under Subscription settlements of the Residential Exchange Program.

1.2 Rate Table

<i>Applicable Months</i>	<i>Rate</i>
January	\$2.14/kW-mo
February	\$2.06/kW-mo
March	\$1.96/kW-mo
April	\$1.37/kW-mo
May	\$1.32/kW-mo
June	\$1.69/kW-mo
July	\$2.12/kW-mo
August	\$2.44/kW-mo
September	\$2.28/kW-mo
October	\$1.90/kW-mo
November	\$2.31/kW-mo
December	\$2.40/kW-mo

B. ENERGY RATE

1. PF Exchange Program Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to customers purchasing power for all five years of the rate period under the Residential Exchange Program.

1.2 Rate Table

<i>Applicable Months</i>	<i>Energy Rate</i>
January	30.11 mills/kWh
February	28.67 mills/kWh
March	27.52 mills/kWh
April	19.68 mills/kWh
May	18.14 mills/kWh
June	22.80 mills/kWh
July	31.49 mills/kWh
August	45.01 mills/kWh
September	35.08 mills/kWh
October	27.78 mills/kWh
November	34.58 mills/kWh
December	35.43 mills/kWh

2. PF Exchange Subscription Energy Rates for FY 2002 through FY 2006

2.1 Applicability

These rates apply to eligible customers purchasing power under Subscription settlements of the Residential Exchange Program for all five years of the rate period.

2.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	19.66 mills/kWh	14.05 mills/kWh
February	18.55 mills/kWh	13.44 mills/kWh
March	17.78 mills/kWh	12.69 mills/kWh
April	12.24 mills/kWh	9.15 mills/kWh
May	11.81 mills/kWh	7.62 mills/kWh
June	15.11 mills/kWh	9.21 mills/kWh
July	19.45 mills/kWh	16.20 mills/kWh
August	29.84 mills/kWh	19.83 mills/kWh
September	20.69 mills/kWh	20.00 mills/kWh
October	17.28 mills/kWh	13.95 mills/kWh
November	21.16 mills/kWh	18.37 mills/kWh
December	22.00 mills/kWh	18.27 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section IV.H below.
The rate for Load Variance is 0.8 mills/kWh.

SECTION IV.

The rates described above apply to the following:

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.	Customers who purchase under the Residential Exchange Program or
Subscription settlements of the Residential Exchange Program
1. Priority Firm Exchange Program Power
 2. Priority Firm Exchange Subscription 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 Generation System Peak
as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement
as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible PF Rate Option	II.L.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

G. SLICE PRODUCT

Purchases of the Subscription Slice Product are limited to Public Body 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Low Density Discount	II.P.
Slice True-Up Adjustment	II.R.
Unauthorized Increase Charge	II.V.

H. CUSTOMERS WHO PURCHASE UNDER RESIDENTIAL EXCHANGE PROGRAM OR SUBSCRIPTION SETTLEMENTS OF THE RESIDENTIAL EXCHANGE PROGRAM

The PF Exchange rates include: (1) the PF Exchange Program rate; and (2) the PF Exchange Subscription rate.

1. Priority Firm Exchange Program Power

This PF Exchange Program rate applies to the traditional implementation of the Residential Exchange Program.

a. Priority Firm Exchange Program Power Charges

1.1 Demand Charge

The charge for Demand will be:
(the Purchaser's Billing Demand, which is calculated by applying the load factor, determined as specified in the Residential Exchange Program agreement, to the Billing Energy for each billing period)
multiplied by
the Demand Rate from Section III.A.

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 residential load for each billing period computed in accordance with the provisions of the Purchaser's Residential Exchange Program agreement)
multiplied by
the Energy Rate from Section III.B.1.

1.3 Load Variance Charge

The charge for Load Variance is embedded in the energy charge.

b. Transmission Charges

Customers purchasing under this rate schedule are charged for transmission services under the NT rate schedule or its successor.

Customers purchasing under this rate schedule are charged for Load Regulation under the applicable charge established by the TBL or its successor.

c. Adjustments, Charges, and Special Rate Provisions

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

2. Priority Firm Exchange Subscription Power

This PF Exchange Subscription rate applies to sales under section 5(c) of the Northwest Power Act to investor-owned utilities (IOU) that participate in a settlement of the Residential Exchange Program as described in BPA's Subscription Strategy.

a. Priority Firm Exchange Subscription Power Charges

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the Demand Rate from Section III.A.

1.2 Energy Charge

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

- (1) The Purchaser's HLH Contract Energy
multiplied by
the HLH Energy Rate from Section III.B.2.
- (2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section III.B.2.

1.3 Load Variance Charge

Not applicable.

b. Adjustments, Charges, and Special Rate Provisions

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed PF Rate	II.D.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

SECTION IV. 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.1.

SCHEDULE RL-02 RESIDENTIAL LOAD FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest. The Residential Load (RL) Firm Power Rate is available to investor-owned utilities (IOUs) under net requirement contracts for resale to ultimate residential consumers for direct consumption. Further, in order to purchase under this rate, the IOU must agree to waive its right to request benefits under section 5(c) of the Northwest Power Act for the term of the contract. Each IOU will be able to purchase a specified amount of Firm Power at the RL-02 rate. Additional sales of requirements power to IOUs will be made at the NR-02 rate.

The product will be delivered in equal hourly amounts over the rate period. The consumer bills of participating IOUs should designate "Benefits of the Federal Columbia River Power System (FCRPS)" to describe the amount of benefits each consumer receives.

Rates in this schedule are available for purchases under requirements sales contracts for a five-year period. Only the block product is available under this rate schedule.

Sales under this schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

The rates for the RL Firm Power product are identified below.

A. DEMAND RATE

1. Monthly Demand for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for five years.

1.2 Rate Table

<i>Applicable Months</i>	<i>Rate</i>
January	\$2.14/kW-mo
February	\$2.06/kW-mo
March	\$1.96/kW-mo
April	\$1.37/kW-mo
May	\$1.32/kW-mo
June	\$1.69/kW-mo
July	\$2.12/kW-mo
August	\$2.44/kW-mo
September	\$2.28/kW-mo
October	\$1.90/kW-mo
November	\$2.31/kW-mo
December	\$2.40/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	19.66 mills/kWh	14.05 mills/kWh
February	18.55 mills/kWh	13.44 mills/kWh
March	17.78 mills/kWh	12.69 mills/kWh
April	12.24 mills/kWh	9.15 mills/kWh
May	11.81 mills/kWh	7.62 mills/kWh
June	15.11 mills/kWh	9.21 mills/kWh
July	19.45 mills/kWh	16.20 mills/kWh
August	29.84 mills/kWh	19.83 mills/kWh
September	20.69 mills/kWh	20.00 mills/kWh
October	17.28 mills/kWh	13.95 mills/kWh
November	21.16 mills/kWh	18.37 mills/kWh
December	22.00 mills/kWh	18.27 mills/kWh

C. LOAD VARIANCE RATE

Not applicable.

SECTION III. BILLING FACTORS AND ADJUSTMENTS

Eligible customers purchasing power under a contract implementing Subscription settlements of the Residential Exchange Program are subject to the charges specified below.

1. Residential Load Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's Contract Demand
multiplied by
the 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 Contract Energy
multiplied by
the HLH Energy Rate from Section II.B; and
- (2) The Purchaser's LLH Contract Energy
multiplied by
the LLH Energy Rate from Section II.B.

2. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions are described in the 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Unauthorized Increase Charge	II.V.

SECTION IV. TRANSMISSION

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

SCHEDULE NR-02 NEW RESOURCE FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power or capacity to be used within the Pacific Northwest. New Resource Firm Power is available to investor-owned utilities (IOU) under net requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power 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 are available for purchases under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contract), for a three or five-year period. Products available under this rate schedule are defined in BPA's 2002 General Rate Schedule Provisions (2002 GRSPs).

This rate schedule supersedes the NR-96 rate schedule, which went into effect October 1, 1996. Sales under the NR-02 rate schedule are subject to BPA's 2002 GRSPs and billing process.

SECTION II. RATES TABLES

The rates in this section apply to NR products.

A. DEMAND RATE

1. Monthly Demand Rate for FY 2002 through FY 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for three or five years.

1.2 Rate Table

<i>Applicable Months</i>	<i>Rate</i>
January	\$2.14/kW-mo
February	\$2.06/kW-mo
March	\$1.96/kW-mo
April	\$1.37/kW-mo
May	\$1.32/kW-mo
June	\$1.69/kW-mo
July	\$2.12/kW-mo
August	\$2.44/kW-mo
September	\$2.28/kW-mo
October	\$1.90/kW-mo
November	\$2.31/kW-mo
December	\$2.40/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2004

1.1 Applicability

These rates apply to eligible customers purchasing power in the first three years of the rate period.

1.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	40.75 mills/kWh	29.41 mills/kWh
February	38.50 mills/kWh	28.19 mills/kWh
March	36.96 mills/kWh	26.68 mills/kWh
April	25.76 mills/kWh	19.52 mills/kWh
May	24.88 mills/kWh	16.41 mills/kWh
June	31.56 mills/kWh	19.64 mills/kWh
July	40.34 mills/kWh	33.76 mills/kWh
August	61.32 mills/kWh	41.09 mills/kWh
September	42.83 mills/kWh	41.44 mills/kWh
October	35.94 mills/kWh	29.22 mills/kWh
November	43.78 mills/kWh	38.15 mills/kWh
December	45.47 mills/kWh	37.95 mills/kWh

2. Monthly Energy Rates for FY 2005 through FY 2006

2.1 Applicability

These rates apply to purchases during the last two years of the rate period for eligible customers purchasing for all five years of the rate period.

2.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	42.25 mills/kWh	30.91 mills/kWh
February	40.00 mills/kWh	29.69 mills/kWh
March	38.46 mills/kWh	28.18 mills/kWh
April	27.26 mills/kWh	21.02 mills/kWh
May	26.38 mills/kWh	17.91 mills/kWh
June	33.06 mills/kWh	21.14 mills/kWh
July	41.84 mills/kWh	35.26 mills/kWh
August	62.82 mills/kWh	42.59 mills/kWh
September	44.33 mills/kWh	42.94 mills/kWh
October	37.44 mills/kWh	30.72 mills/kWh
November	45.28 mills/kWh	39.65 mills/kWh
December	46.97 mills/kWh	39.45 mills/kWh

3. Monthly Energy Rates for FY 2002 through FY 2006

3.1 Applicability

These rates apply to eligible customers purchasing for all five years of the rate period under this rate table.

3.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	41.35 mills/kWh	30.01 mills/kWh
February	39.10 mills/kWh	28.79 mills/kWh
March	37.56 mills/kWh	27.28 mills/kWh
April	26.36 mills/kWh	20.12 mills/kWh
May	25.48 mills/kWh	17.01 mills/kWh
June	32.16 mills/kWh	20.24 mills/kWh
July	40.94 mills/kWh	34.36 mills/kWh
August	61.92 mills/kWh	41.69 mills/kWh
September	43.43 mills/kWh	42.04 mills/kWh
October	36.54 mills/kWh	29.82 mills/kWh
November	44.38 mills/kWh	38.75 mills/kWh
December	46.07 mills/kWh	38.55 mills/kWh

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 is applicable to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

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-02 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 a NLSL are subject to the charges specified below.

1. New Resource Firm Power

1.1 Demand Charge

The charge for Demand will be:
the NLSLs Demand Entitlement as
specified in the contract
multiplied by
the 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 NLSLs HLH Energy Entitlement as
specified in the contract
multiplied by
the HLH Energy Rate from Section II.B.
- (2) the NLSLs LLH Energy Entitlement as
specified in the contract
multiplied by
the LLH Energy Rate from Section II.B.

1.3 Load Variance Charge

The charge for Load Variance will be
the NLSLs 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Measured Demand on the Generation System Peak as
specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement as
specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement
multiplied by
a Demand Adjuster) as specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Excess Factoring Charge	II.I.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

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 Demand Entitlement as
specified in the contract
multiplied by
the 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 HLH Energy Rate from Section II.B.
- (2) The Purchaser's LLH Energy Entitlement as
specified in the contract
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below:

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible NR Rate Option	II.K.
Green Energy Premium	II.M.
Low Density Discount	II.P.
Rate Melding	II.Q.
Stepped Up Multiyear Block (SUMY)	II.S.
Targeted Adjustment Charge	II.U.
Unauthorized Increase Charge	II.V.

SECTION IV. TRANSMISSION

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

IP-02 INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available, in conjunction with the IPTAC, to BPA's direct service industrial (DSI) customers for Firm Power to be used in their industrial operations. DSIs that purchase power under contracts for which power deliveries begin on or after October 1, 2001 (2002 Contracts), are eligible to purchase under this rate schedule for up to a five-year period.

This rate schedule supersedes the IP-96 rate schedule, which went into effect October 1, 1996. Sales under the IP-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs) and billing process.

SECTION II. RATES TABLES

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

A. DEMAND RATE FOR ALL IP/IPTAC PRODUCTS

1. Flat Rate Demand for FY 2002 through 2006

1.1 Applicability

These rates apply to eligible customers purchasing power for all five years of the rate period.

1.2 Rate Table

<i>Applicable Months</i>	<i>Rate</i>
January	\$2.14/kW-mo
February	\$2.06/kW-mo
March	\$1.96/kW-mo
April	\$1.37/kW-mo
May	\$1.32/kW-mo
June	\$1.69/kW-mo
July	\$2.12/kW-mo
August	\$2.44/kW-mo
September	\$2.28/kW-mo
October	\$1.90/kW-mo
November	\$2.31/kW-mo
December	\$2.40/kW-mo

B. ENERGY RATE

1. Monthly Energy Rates for FY 2002 through FY 2006

1.1 Applicability

These energy rates are to be combined with one of the two IP Targeted Adjustment Charges specified in Section 2.2 or 3.2 below.

1.2 Rate Table

<i>Applicable Months</i>	<i>HLH Rate</i>	<i>LLH Rate</i>
January	21.49 mills/kWh	15.87 mills/kWh
February	20.37 mills/kWh	15.27 mills/kWh
March	19.61 mills/kWh	14.52 mills/kWh
April	14.07 mills/kWh	10.98 mills/kWh
May	13.63 mills/kWh	9.44 mills/kWh
June	16.93 mills/kWh	11.04 mills/kWh
July	21.28 mills/kWh	18.03 mills/kWh
August	31.66 mills/kWh	21.65 mills/kWh
September	22.51 mills/kWh	21.83 mills/kWh
October	19.10 mills/kWh	15.78 mills/kWh
November	22.99 mills/kWh	20.20 mills/kWh
December	23.82 mills/kWh	20.10 mills/kWh

2. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (23.5 mills)

2.1 These rates apply to the eligible customers purchasing power under this rate schedule for all five years of the rate period.

2.2 A charge of 2.02 mills shall be added to each IP energy rate in the Rate Table in 1.2 above.

3. Monthly Energy Rates for FY 2002 through FY 2006 for IPTAC (25.0 mills)

3.1 These rates apply to the eligible customers purchasing power under this rate schedule for all five years of the rate period.

3.2 A charge of 3.52 mills shall be added to each IP energy rate in the Rate Table in 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance rate for FY 2002 through FY 2006 applies to all customers purchasing power under this rate schedule unless specifically excluded in Section III below. The rate for Load Variance is 0.8 mills/kWh.

SECTION III. BILLING FACTORS AND ADJUSTMENTS FOR EACH IP PRODUCT

This rate schedule contains two subsections, corresponding to the products to which this rate schedule applies. Only the firm take-or-pay Block Product is available under these rate schedules.

SECTION III.A. DSI Customers Who Purchase Under 2002 Industrial Firm Power (IP) Contracts

SECTION III.B. DSI Customers Who Purchases Under 2002 Industrial Firm Power Targeted Adjustment Charge (IPTAC) Contracts

A. DSI CUSTOMERS WHO PURCHASE UNDER 2002 INDUSTRIAL FIRM POWER (IP) CONTRACTS

Purchases of power under a 2002 IP contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Contract Demand
multiplied by
the 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 monthly HLH Contract Energy
multiplied by
the HLH Energy Rate from Section II.B; and
- (2) the Purchaser's monthly LLH Contract Energy
multiplied by
the 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 2002 GRSPs. Relevant sections are identified below:

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewable Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Green Energy Premium	II.M.
Rate Melding	II.Q.
Supplemental Contingency Reserves Adjustment	II.T.
Unauthorized Increase Charge	II.V.

**B. DSI CUSTOMERS WHO PURCHASE UNDER 2002 INDUSTRIAL FIRM
POWER TARGETED ADJUSTMENT CHARGE (IPTAC) CONTRACTS**

Purchases of power under a 2002 IPTAC contract are subject to the charges specified below.

1. Industrial Firm Power

1.1 Demand Charge

The charge for Demand will be:
the Purchaser's monthly Contract Demand
multiplied by
the Demand Rate from Section II.A.

1.2 Energy Charge

Energy charges will be calculated pursuant to the GRSPs IPTAC at the time of contract negotiations.

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 2002 GRSPs. Relevant sections are identified below:

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Conservation and Renewable Discount	II.A.
Conservation Surcharge	II.B.
Cost-Based Indexed IP Rate	II.C.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Flexible IP Rate Option	II.J.
Green Energy Premium	II.M.
Industrial Firm Power Targeted Adjustment Charge	II.O.
Rate Melding	II.Q.
Supplemental Contingency Reserves Adjustment	II.T.
Unauthorized Increase Charge	II.V.

SECTION IV. TRANSMISSION

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

NF-02
NONFIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available for the purchase of nonfirm energy to be used both inside and outside the United States including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of nonfirm energy under this schedule shall be determined by BPA.

This rate schedule supersedes the NF-96 schedule, which went into effect on October 1, 1996. Sales under the NF-02 rate schedule are subject to BPA's 2002 General Rate Schedule Provisions (2002 GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's 2002 GRSPs and billing process.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

The average cost of nonfirm energy is 24.98 mills/kWh. The NF-02 rate schedule provides for upward and downward pricing flexibility from this average nonfirm energy cost.

A. RATES FOR NONFIRM ENERGY

1. Standard Rate

The Standard rate is any offered rate not to exceed 29.98 mills/kWh.

2. Market Expansion Rate

The Market Expansion rate is any offered rate below the Standard rate in effect. BPA may have one or more Market Expansion rates in effect simultaneously.

3. Incremental Rate

The Incremental Rate is the Incremental Cost of energy plus 2.00 mills/kWh, where the Incremental Cost is defined as all identifiable costs (expressed in mills/kWh) that BPA would have avoided had it not produced or purchased the energy being sold under this rate.

4. Contract Rate

The Contract Rate is 24.98 mills/kWh.

B. BILLING FACTOR FOR NONFIRM ENERGY

The billing factor for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

C. ADJUSTMENTS FOR NONFIRM ENERGY

All adjustments are described in the 2002 GRSPs. The applicable sections are identified for each adjustment.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>2002 GRSP Section</i>
Cost Contributions	II.E.
Unauthorized Increase Charge	II.V.

SECTION III. DETERMINATION OF THE APPLICABLE NF RATE

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or any combination of these rates may be in effect.

A. STANDARD RATE

The Standard rate is available for all purchases of nonfirm energy.

B. MARKET EXPANSION RATE

1. Application of the Market Expansion Rate

The Market Expansion rate applies when BPA determines that all markets at the Standard rate have been satisfied and BPA offers additional nonfirm energy.

2. Market Expansion Rate Qualification Criteria

In order to purchase nonfirm energy at the Market Expansion rate, a purchaser must:

- a. have a displaceable resource, displaceable purchase of electricity; or
- b. be an end-user load with a displaceable alternative fuel source.

In addition, a purchaser must demonstrate one of the following:

- a. shutdown or reduction of the output of the displaceable resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or
- b. reduction of a displaceable purchase and the output of the resource associated with that purchase, in an amount equal to the amount of Market Expansion rate energy purchased; or
- c. shutdown or reduction of the identified output of the resource(s) indirectly in an amount equal to the amount of Market Expansion rate energy purchased (for example, the purchase may be used to run a pumped storage unit); or
- d. decrease of an end-user alternate fuel source in an amount equivalent to the amount of Market Expansion rate energy purchased.

3. Eligibility Criteria for Market Expansion Rate

a. When only one Market Expansion rate is offered:

Purchasers satisfying the Market Expansion Rate Qualifying Criteria specified in Section III.B.2 above, who purchased nonfirm energy directly from BPA, are eligible to purchase power under the Market Expansion rate offered if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh.

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy through a third party are eligible to purchase power under the Market Expansion rate offered if the cost of the qualifying alternative fuel source is lower than the Standard rate in effect plus 4.00 mills/kWh.

b. When more than one Market Expansion rate is offered:

Purchasers qualifying under Section III.B.2 who purchase nonfirm energy directly from BPA are eligible to purchase power under the Market Expansion rate if the decremental cost of the qualifying resource, purchase, or qualifying alternative fuel source is lower than the Standard rate in effect plus 2.00 mills/kWh. The rate applicable to a purchaser will be the highest Market Expansion rate offered that is below the purchaser's qualifying decremental cost *minus* 2.00 mills/kWh.

C. INCREMENTAL RATE

The Incremental rate applies to sales of energy:

1. that is produced or purchased by BPA concurrently with the nonfirm energy sale;
2. that BPA may at its option not produce or purchase; and
3. that has an Incremental Cost greater than the Standard rate (plus the Intertie Charge, if applicable) minus 2 mills.

D. CONTRACT RATE

The Contract rate applies to contracts (except power sales contracts offered pursuant to Sections 5(b), 5(c), and 5(g) of the Northwest Power Act) that refer to the Contract rate:

1. for sale of nonfirm energy; or
2. for determining the value of energy.

E. WESTERN SYSTEMS POWER POOL TRANSACTIONS (WSPP)

BPA may make available nonfirm energy for transactions under the WSPP agreement. WSPP sales shall be subject to the terms and conditions specified in the WSPP agreement and will be consistent with regional and public preference. The rate for transactions under the WSPP agreement is any rate within the limits specified by the Standard, Market Expansion, and Incremental rates but may not exceed the maximum rate specified in the WSPP agreement. The rate for WSPP sales may differ from the actual rate offered for non-WSPP transactions in any hour. The rate for WSPP transactions is independent of any other rate offered concurrently under this rate schedule outside the agreement.

F. END-USER RATE

BPA may agree to a rate formula for nonfirm energy purchases by end-users. Such rate or rate formula will be within the limits specified for the Standard and Market Expansion rates but may differ from the actual rates offered during any hour.

SECTION IV. DELIVERY

A. RATE OF DELIVERY

BPA shall determine the amount of nonfirm energy to be made available for each hour. Such determination shall be made for each applicable nonfirm energy rate.

B. GUARANTEED DELIVERY

1. Availability

BPA will determine the amount and duration of nonfirm energy to be offered on a guaranteed basis. Such daily or hourly amounts may be as small as zero or as much as all the nonfirm energy that BPA plans to offer for sale on such days.

2. Conditions

Scheduled amounts of guaranteed nonfirm energy may not be changed except:

- a. when BPA and the purchaser mutually agree to increase or decrease the scheduled amounts; or
- b. when BPA must reduce nonfirm energy deliveries in order to serve firm loads.

SECTION V. TRANSMISSION

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

BPA'S 2002
GENERAL RATE SCHEDULE PROVISIONS
FOR POWER RATES

INDEX

GENERAL RATE SCHEDULE PROVISIONS

Subject	Page
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SECTION I: ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A.	Approval of Rates	77
B.	General Provisions	77
C.	Late Payment Provisions	77
D.	Notices	78

SECTION II: ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A.	Conservation and Renewables Discount (C&R Discount).....	79
B.	Conservation Surcharge (PF/NR only)	83
C.	Cost-Based Indexed IP Rate	83
D.	Cost-Based Indexed PF Rate	83
E.	Cost Contributions	84
F.	Cost Recovery Adjustment Clause (CRAC)	85
G.	Demand Adjuster	88
H.	Dividend Distribution Clause (DDC)	88
I.	Excess Factoring Charges	92
J.	Flexible IP Rate Option	94
K.	Flexible NR Rate Option	95
L.	Flexible PF Rate Option	95
M.	Green Energy Premium	96
N.	Guaranteed Delivery Charge (NF Only)	98
O.	Industrial Firm Power Targeted Adjustment Charge (IPTAC)	98
P.	Low Density Discount	98
Q.	Rate Melding	102
R.	Slice True-Up Adjustment	102
S.	Stepped Up Multiyear Block (SUMY).....	104
T.	Supplemental Contingency Reserves Adjustment (SCRA)	105
U.	Targeted Adjustment Charge	106
V.	Unauthorized Increase Charge	108

SECTION III: DEFINITIONS

A.	Power Products and Services Offered By the Power Business Line of BPA	
1.	Actual Partial Service Product – Simple/Complex	110
2.	Block Product	110
3.	Block Product with Factoring	110

SECTION III: DEFINITIONS (Continued)

4.	Block Product with Shaping Capacity	110
5.	Construction, Test and Start-Up and Station Service	110
6.	Core Subscription Products	111
7.	Customer System Peak (CSP)	111
8.	Full Service Product	111
9.	Industrial Firm Power	112
10.	Load Variance	112
11.	New Resource Firm Power	112
12.	Nonfirm Energy	112
13.	Priority Firm Power	113
14.	Regulation and Frequency Response	113
15.	Residential Exchange Program Power	113
16.	Slice Product	114
 B. Definition of Rate Schedule Terms		
1.	2002 Contract	114
2.	Annual Billing Cycle	114
3.	Billing Demand	114
4.	Billing Energy	114
5.	California Independent System Operator (ISO)	114
6.	California ISO Spinning Reserve Capacity	115
7.	California ISO Supplemental Energy	115
8.	California Power Exchange (California PX)	115
9.	Contract Demand	115
10.	Contract Energy	115
11.	Control Area	115
12.	Decremental Cost	116
13.	Delivering Party	116
14.	Demand Entitlement	116
15.	Discount Period	116
16.	Dow Jones Mid-C Indexes (DJ Mid-C Indexes)	116
17.	Electric Power	116
18.	Energy Entitlement	117
19.	Federal System	117
20.	Firm Power (PF-02, IP-02, NR-02, RL-02)	117
21.	Full Service Customer	117
22.	Generation System Peak	117
23.	Heavy Load Hours (HLH)	118
24.	Inventory Solution Costs	118
25.	Light Load Hour (LLH)	118
26.	Measured Demand	118
27.	Measured Energy	119

SECTION III: DEFINITIONS (Continued)

28.	Metered Demand	119
29.	Metered Energy	120
30.	Mid-Columbia Bus (Mid-C Bus)	120
31.	Monthly Federal System Peak Load	120
32.	NP15	120
33.	NW1 (California-Oregon Border)	120
34.	NW3 (Nevada-Oregon Border)	120
35.	Partial Service Customer	120
36.	Point of Delivery (POD)	121
37.	Point of Integration (POI)	121
38.	Point of Interconnection (POI)	121
39.	Points of Metering (POM)	121
40.	Pre-Subscription Contract	121
41.	Purchaser	121
42.	Receiving Party	121
43.	Retail Access	121
44.	Scheduled Demand	122
45.	Scheduled Energy	122
46.	Slice Administrative Costs	122
47.	Slice Revenue Requirement	122
48.	Subscription	125
49.	Subscription Contract	125
50.	System Obligations	125
51.	Total Plant Load	125
52.	Total Retail Load (TRL)	125
53.	Utility Distribution Company	125

GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

These 2002 Wholesale Power Rate Schedules and General Rate Schedule Provisions (2002 GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). Bonneville Power Administration (BPA) has requested that FERC make these rates and 2002 GRSPs effective on October 1, 2001, for customers who are billed by BPA on a calendar month basis and on the first day of the first billing month following that date for all other customers. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These 2002 Wholesale Power Rate Schedules and the 2002 GRSPs associated with these schedules supersede BPA's 1996 rate schedules (which became effective October 1, 1996) to the extent stated in the Availability section of each rate schedule. These schedules and 2002 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 Federal Columbia River Transmission System (FCRTS) 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 2002 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. Late Payment Provisions

Bills not paid in full on or before close of business on the due date shall be subject to an interest charge of one-twentieth percent (0.05 percent) applied each day to the unpaid amount. This interest charge shall be assessed on a daily basis until such time as the unpaid amount is paid in full.

Remittances will be accepted without assessment of the charges referred to in the preceding paragraph provided payment was received on or before the due date. The due date is the 20th day after the issue date of the bill unless the 20th day is a Saturday, Sunday, or Federal holiday, in which case the due date is the next business day. Whenever a power bill or a portion thereof remains unpaid subsequent to the due date, and after giving 30 days' advance notice in writing, BPA may cancel the contract for service to the Purchaser. However, such cancellation shall not affect the Purchaser's liability for any previously accrued charges under such contract.

D. Notices

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

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation and Renewables Discount (C&R Discount)

1. Description of the Discount

To encourage and support the development of conservation projects and renewable resources in the Pacific Northwest, BPA is offering a Conservation and Renewables Discount (C&R Discount) to customers purchasing under the Priority Firm (PF-02), New Resources (NR-02), and Residential Load (RL-02) rate schedules. Customers purchasing under the Industrial Firm Power Rate (IP-02) will be eligible to the extent that the C&R Discount does not reduce their effective rate below the DSI floor rate. Regional public agency customers with Pre-Subscription contracts with collared pricing provisions may be eligible for the C&R Discount subject to contract provisions. The amount of the Discount will be a fixed monthly amount based on the customer's forecasted purchases from BPA under its Subscription contract. Following the end of the Discount Period (which is the end of the rate period or the customer's contract term, whichever comes first), BPA will evaluate the customer's investments in eligible conservation and renewable resource projects during the Discount Period. Any customer that has not spent at least as much money on eligible activities as the cumulative discount received from BPA must reimburse the difference to BPA.

2. Calculation and Application of the Discount

a. Overview of the Discount

The C&R Discount will be included as a fixed dollar credit in the monthly power bill of each participating customer. The credit will equal the customer's forecasted average monthly Subscription contract (in megawatts) multiplied by the unit discount. (Because the *average* contract is used, the discount does not vary by month).

b. Determination of the "Unit Discount"

The unit discount will equal 0.5 mills per kilowatthour (kWh).

c. Determination of Individual Customer Discounts

For a participating customer buying power from BPA under a Subscription contract for the entire five-year rate period, BPA will determine the monthly dollar discount by multiplying the customer's forecasted *average* monthly power consumption over the rate period by the unit discount.

d. Annual Review of Individual Customer Discounts

At least 30 days prior to the start of each fiscal year, customers will submit adjustments to the section c monthly discounts based on changes to the customers load as specified in their BPA contract.

e. Application of the Discount

The C&R Discount will be applied after BPA has determined all other charges and credits on the participating customer's power bill.

BPA will provide the discount *even in* those months when the discount amount is larger than the customer's total power bill amount.

3. Qualifying Expenditures

Participating customers shall record all qualifying expenditures to ensure full credit for their conservation and renewable resource activities. Qualifying expenditures are those that meet technical standards developed by the Regional Technical Forum as approved by BPA.

Although BPA will provide the credit on a monthly basis, the customer has no obligation to adhere to any particular expenditure pattern. To retain the full discount provided by BPA, the participating customer must make qualifying expenditures during the Discount Period in an amount equal to, or exceeding, the cumulative C&R Discount received from BPA during the Discount Period.

4. Reporting

a. Interim Conservation and Renewable Reports

Participating customers shall submit to BPA annual Interim Conservation and Renewable Reports at the end of each fiscal year of the rate period (i.e., 10/01/01 to 9/30/02; 10/01/02, to 9/30/03; etc.). The Interim Report shall show the customer's cumulative discounts received to date and their cumulative qualifying expenditures. If the report shows that the customer's qualifying expenditures are less than or equal to its discount receipts by 5 percent or more, the customer must indicate in its report how it plans to adjust its expenditures to ensure that it will retain the full discount after the Discount Period.

b. Final Reconciliation Reports

At the end of the Discount Period the participating customer shall prepare a Final Reconciliation Report. This report shall be submitted and received by BPA one month after the end of the Discount Period (November 1,

2006, for participating customers' purchasing power from BPA for the full five-year rate period).

This report shall identify:

- i. The cumulative C&R Discount that the customer has received from BPA during the Discount Period, and
- ii. The total qualifying expenditures that the customer has made during the Discount Period segregated into the following four categories:
 - I. Incremental Conservation
 - II. Renewable Resources
 - III. Low Income Weatherization
 - IV. Support Activities (i.e., administrative, advertising, R&D, and evaluation)

c. Certification of Incremental Spending

Each Interim Report and the Final Reconciliation Report shall include language certifying the participating customer's actual incremental spending, such as:

"[Customer] certifies that the expenditures documented in this report are incremental increases in this organization's budget for the current operating year beyond what we planned to spend absent the discount."

d. Exemption Language for State and Municipal Initiatives

If states, municipalities, or other governmental bodies in the BPA service territory require, by law or regulation, that a utility, which is a participating customer in the C&R Discount, to acquire or invest in new conservation and/or a new renewable resource project, then such acquisitions and investments will be deemed as incremental budget increases for the purposes of section 4.c. above.

5. Reimbursement

a. Customers Whose Expenditures Exceed the Threshold

No reimbursements are required of any participating customer whose total expenditures over the Discount Period equal or exceed the total cumulative C&R Discount received from BPA.

b. Customers Whose Expenditures Fall Below the Threshold

If a participating customer's Final Reconciliation Report shows that the cumulative discount received from BPA exceeds the customer's total qualifying expenditures, the customer may take an additional month (for a total of two months after the end of the Discount Period) to make the necessary qualifying expenditures and prepare a Revised Final Reconciliation Report. The final report is due to BPA within two months of the end of the Discount Period (December 1, 2006, for the five-year customers). If the customer's qualifying expenditures still do not equal or exceed its cumulative discount, the customer must reimburse the difference to BPA. Such reimbursement shall be made within the same two-month grace period and shall be made using the same payment method as the customer uses for paying its wholesale bill.

BPA will not assess interest on any reimbursement paid within the two-month window. However, any payment received after the due date (December 1, 2006, the five-year customers) shall be subject to a late payment charge as described in their Subscription contract.

6. Revenue Dividends

a. Implementation

If BPA declares that there is a dividend during this rate period, the first \$15 million will be allocated to conservation and renewable resource development. BPA will distribute the C&R portion of any declared dividend in the same manner outlined in this section with the following modifications:

1. In order to receive their portion of the C&R dividend, customers must be actively participating in the basic C&R Discount effort; and
2. Participating customers must spend two dollars on eligible activities to receive one dollar of their dividend share (i.e., any C&R dividend will be leveraged on a 2 for 1 basis).
3. The unit discount for participating customers receiving the dividend will set at \$0.75 per MWh during the months the dividend is in effect.

B. Conservation Surcharge (PF/NR Only)

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 PF and NR rate schedules are subject to the Conservation Surcharge.

C. Cost-Based Indexed IP Rate

The Cost-Based Indexed IP Rate option shall be offered at BPA's discretion to a DSI Purchaser who makes a contractual commitment to purchase power for all five years of the rate period from BPA that is subject to the IP Targeted Adjustment Charge (IPTAC). 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 actual charges and billing factors will be mutually agreed to by BPA and the Purchaser. The following criteria will be used in establishing any flexible rate:

1. **Equivalent Net Present Value Revenues:** Forecasted revenues from a Purchaser under this rate option must be equivalent to or greater than, on a net present value basis, the revenues BPA would have received had the IPTAC specified in the IP-02 rate schedule been applied to the same sales.
2. **Risk Adjustments:** Risk, both credit risk associated with individual customers and price risk associated with power and commodity prices, will be factors in establishing any flexible rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a "margin deposit" expense charge built into the rates, or other methods acceptable to BPA.
3. **Industry Index:** The Cost-Based Indexed IP Rate will be adjusted on a regular basis consistent with a negotiated cash or financial index. Adjusting the price of the Cost-Based Indexed IP Rate with the fluctuations in a world aluminum price index would be one use of an industry index.
4. **Lower Rate Limit and Upper Rate Limit:** A lower and upper rate limit will bound the Cost-Based Index and establish the minimum and maximum prices to be charged during the contract period.

D. Cost-Based Indexed PF Rate

The Cost-Based Indexed PF Rate will be offered to all firm load requirements customers who wish to convert their applicable PF rate under their contracts to a market-indexed or floating price adjusted for BPA's risk. The following are features of this rate:

1. BPA and the customer will choose during contract negotiations a mutually agreed reference point and sponsor for the index used. For example, the California-Oregon border (location) and the Dow Jones cash or the New York Mercantile Exchange futures (sponsor), or some other combination to arrive at an agreed upon index.
2. BPA will base the index pricing on a current market forecast of the market index referenced. The expected Net Present Value (NPV) revenue of the forecast index prices will be adjusted by a HLH and a LLH Market Index Monthly Adjustment (MIMA) to equal the expected NPV of the applicable PF rates. The MIMA reflects BPA's PF equivalent expected revenues at the time the contract is signed, including an insurance premium to ensure revenue sufficiency.
3. Customers must select this rate for the term of their Subscription contract that the 2002-2006 rate period covers. Customers who choose a contract length of less than five years and wish to renew will be subject to rates established under a new rate case.
4. Billing will be based on the index's average of the last 15 days of closing or posted daily prices at the reference point. The MIMA will be calculated as follows:

Index = average of last 15 days of closing or posted
daily prices at the reference point.

PF = monthly PF HLH or LLH energy rate

Cost of Insurance = The premium on a physical and financial instrument
used to mitigate the risk.

MIMA = Index – PF + Cost of Insurance

E. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.12 mills/kWh.

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

Table A

<i>Rate Schedule</i>	<i>Resource Cost Contribution</i>		
	Federal Base System	Exchange	New Resources
PF	100%	0%	0%
IP	52.86%	43.66%	3.48%
NR	52.86%	43.66%	3.48%

F. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to posted power rates for Subscription sales on a temporary basis if Actual Accumulated Net Revenues (AANR) in the generation function fall below a threshold level.

The CRAC applies to power customers under these firm power rate schedules: Priority Firm Power [Preference (PF excluding Slice), Exchange Program, and Exchange Subscription], IP-02, including under the IPTAC and Cost-Based Index Rate, RL-02 including the financial portion of any Residential Exchange Settlement under this rate schedule, NR-02, and Subscription purchase under FPS. The CRAC does not apply to Pre-Subscription rates or Slice purchases.

1. Formula for the Calculation of the Revenue Amount and CRAC Percentage

If the AANR in any fiscal year 2001 through 2004 falls below the CRAC Threshold for that same fiscal year, the CRAC triggers, and rates will be increased for a 12-month period beginning the following April. The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
CRAC Threshold – AANR; or
The annual Maximum Planned Recovery Amount, shown in Table B below.

Where Revenue Amount is the amount of additional revenue that an increase in rates under CRAC is intended to generate during the period that the rate increase is effective;

Where CRAC Threshold is the “trigger point” for invoking a rate increase under the CRAC. The threshold is pre-specified for the end of fiscal years 2001, 2002, 2003, 2004, and 2005 in Table B.

Where AANR is generation function net revenues, as accumulated since 1998, at the end of each of the fiscal years 2001 through 2005. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the CRAC. Accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent auditing firm.

Where Maximum Planned Recovery Amount is the maximum amount planned to be recovered through the CRAC beginning in April following the end of a fiscal year in which the AANR falls below the CRAC Threshold.

If the AANR in fiscal year 2005 falls below the CRAC Threshold, the CRAC triggers, and rates will be increased for a six-month period beginning the following April. The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:
 (CRAC Threshold – AANR) divided by 2; or
 \$87.5 million (\$175 million divided by 2)

Table B

Fiscal Year	CRAC Threshold (AANR, \$ Millions)	Maximum Planned Recovery Amount (Beginning Following April)
2001	-350	125
2002	-350	135
2003	-200	150
2004	-200	150
2005	-200	87.5

Once the Revenue Amount is determined, that amount will be converted to the CRAC Percentage. The CRAC Percentage is the percentage increase in each of the firm power rate schedules listed above. This percentage will be applied for a period of time to generate the additional (CRAC) revenue. The CRAC Percentage will be determined by the following formula:

CRAC Percentage =
 Revenue Amount
 Divided by
 CRAC Revenue Basis,

Where CRAC Revenue Basis is the total generation revenue for the loads subject to CRAC, plus any Slice loads, for the fiscal year in which the CRAC implementation begins, based on the then most current revenue forecast.

Each non-Slice product's total charge for energy, demand and load variance will be increased by this CRAC Percentage amount.

2. CRAC Adjustment Timing

In January of each year of the rate period, the Administrator will determine whether the AANR at the end of the preceding fiscal year fell below the CRAC Threshold. If the AANR is below the CRAC Threshold, the Administrator will propose, in January, to increase applicable rates effective in the following April. The adjustment is applied to power deliveries beginning April 1. Any such increase beginning in fiscal years 2002-2005 remains in effect through March of the following year. An increase beginning in the final fiscal year of the rate period (2006) will remain in effect through September 2006.

3. CRAC Notification Process

BPA shall follow the following notification procedures:

a. Financial Performance Status Reports

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the fiscal year ending September 30. By no later than December 1 of each year, BPA shall also post on its World Wide Web site the unaudited AANR.

b. Notice of CRAC Trigger

BPA shall notify all customers and rate case parties on or about January 15 in each of the fiscal years 2002-2006, if the AANR fell below the CRAC Threshold for that fiscal year and rates will be adjusted under the CRAC. (If the December unaudited AANR report for the generation function indicated that the CRAC Threshold might be reached, and the audited actuals show that it has not triggered, customers and rate case parties will be so notified.) Notification will include the audited AANR for the prior fiscal year, the calculation of the Revenue Amount, and the estimated CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the CRAC implementation process.

On or about February 1 of any of the fiscal years 2002-2006 in which the AANR falls below the CRAC Threshold, BPA staff shall conduct a public forum to explain the AANR result, the calculation of the Revenue Amount and the CRAC Percentage, and demonstrate that the CRAC has been implemented in accordance with the GRSPs. The forum will provide an opportunity for public comment.

On or about March 1 of any of the fiscal years 2002-2006 in which the AANR falls below the CRAC Threshold, the BPA Administrator shall notify all customers to whom the CRAC applies of the final calculation of the adjustment and the resulting rate increase (as a percentage) applicable to each rate schedule.

G. 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 Generation System Peak 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.

H. Dividend Distribution Clause (DDC)

The DDC is a clause establishing criteria and public process requirements that the Administrator will use to decide whether dividends should be distributed and the amount that should be distributed. The DDC enables BPA to distribute dividends to customers and other stakeholders. The DDC also establishes the mechanism to be used to make a distribution to certain firm power customers.

The DDC applies to power customers under these firm power rate schedules: Priority Firm Power [Preference (PF excluding Slice), Exchange Program, and Exchange Subscription], IP-02 including under the IPTAC and Cost-Based Index Rate, RL-02 including the financial portion of any Residential Exchange Settlement under this rate schedule, NR-02, and Subscription purchases under FPS. The DDC does not apply to Pre-Subscription rates or Slice purchases, unless those customers participate in the C&R Discount and a distribution is made to eligible participants of that program.

The DDC does not apportion, or establish criteria for apportioning, dividends to customers under the above firm power rate schedules other than to qualifying power customers participating in the C&R Discount, or to other customers and stakeholders.

"Stakeholders" are groups that have a fundamental policy or financial interest in BPA's generation function. These groups include, but are not limited to, customers subject to the

posted firm power rate schedules cited above. A full identification of stakeholders will be provided for comment in the public consultation process.

1. Formula for the Calculation of the Dividend Distribution Amount

The DDC process will be implemented if audited actual accumulated net revenues for the end of any of the fiscal years 2001-2005 are above the DDC Threshold value.

Actual Accumulated Net Revenues (AANR) are generation function net revenues, as accumulated since 1998, at the end of each of the fiscal years 2001 through 2005. Net revenues are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Practices. Only generation function revenues and expenses, which is to say accrued revenues and accrued expenses that are associated with the production, acquisition, marketing, and conservation of electric power, are included in determinations under the DDC; accrued revenues and expenses of the transmission function are excluded. The determination of AANR will be confirmed by BPA's independent outside auditing firm.

DDC Threshold is the minimum level of AANR that must be realized before a dividend distribution is considered. The DDC Threshold is \$500 million for the end of fiscal years 2001, 2002, 2003, 2004, and 2005.

DDC Amount is the aggregate amount that is available to be distributed to customers and stakeholders. The DDC Amount may be equal to zero and will be determined by the following formula:

DDC Amount is the lower of:
AANR – DDC Threshold; or
Cash in excess of that needed to meet the Treasury Payment Probability (TPP) Standard, based on the Five-Year Forecast

Where the TPP Standard is an 88 percent probability that all planned payments to the U.S. Treasury will be paid on time and in full over the Five-Year Forecast period (or equivalent financial criterion in the event that BPA replaces its TPP Standard); and

Where the Five-Year Forecast is the forecast of accrued revenues and expenses, and the risk analysis and assessment of TPP or any replacement financial criterion, for the current year and subsequent four years that the Administrator prepares and subjects to public review and comment if the DDC Threshold has been met.

The portion of the DDC Amount allocated to power customers (the Power Customers DDC Amount) will be determined according to a plan to be adopted in a public process BPA will conduct (see Section 3 below). The Power Customer DDC Amount will be converted to a percentage (the Power Customer DDC

Percentage), which will be applied to all power customer rates subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers.

The Power Customer DDC Percentage will be determined by the following formula:

Power Customer DDC Percentage equals:
Power Customer DDC Amount
Divided by the
DDC Revenue Basis

Where DDC Revenue Basis is the total generation revenue for the loads subject to the DDC for the fiscal year in which the DDC implementation begins, based on the then most current revenue forecast.

Each covered power customer will receive a rebate equal to the Power Customer DDC Percentage applied to their total charge for energy, demand and load variance. For any customer or stakeholder entitled to a dividend who is not a power customer, the Administrator will convert the DDC Percentage to a dollar figure.

2. Determination and Timing of a Dividend Distribution

On or about January 15 of each year of the rate period (FY 2002-2006), the Administrator will determine whether the AANR exceeds the DDC Threshold. If the AANR exceeds the DDC Threshold: (1) customers and rate case parties will be so notified; and (2) the Administrator will prepare a Five-Year Forecast. On or about March 1, the Administrator will propose to distribute or not distribute dividends. The Administrator will issue a final decision on the proposal on or about April 15.

Dividends distributed to customers are included in energy deliveries beginning May 1, and, for any fiscal year 2002-2005, remain in affect for 12 months i.e., through April 30 of the following year. In the last year of the rate period (FY 2006), the rebate would expire on September 30, 2006.

3. Determining How the Distribution is Allocated

The first \$15 million of the DDC Amount, if the DDC Amount exceeds \$15 million, or the entire DDC Amount if it equals \$15 million or less, will be allocated to qualifying customers participating in the Conservation and Renewables Discount Program (C&R Discount). The C&R Discount is a rate mechanism designed to encourage incremental conservation and renewable resource development by BPA's power purchasers under PF, IP, RL, and NR rate schedules. See Conservation and Renewables Discount GRSP, Section II.A.

BPA intends to conduct a separate public consultation process by October 1, 2001, to develop the criteria for allocating any remaining DDC Amount (exceeding the \$15 million for the C&R Discount) among customers and stakeholders.

4. Dividend Distribution Notification Process

BPA shall follow the following notification procedures:

a. Financial Performance Status Reports

By no later than August 31 of each year, BPA shall post on its electronic information access site (World Wide Web) a forecast of AANR attributable to the generation function for the fiscal year ending September 30. By December 1 of each year, BPA shall post on its World Wide Web site the unaudited AANR.

b. Notice of DDC Trigger

On or about January 15 in each of the fiscal years 2002-2006, BPA will notify all power customers and rate case parties if the AANR exceeds the DDC Threshold. (If the December unaudited AANR report for the generation function indicated that the DDC Threshold might be exceeded, and the audited actuals show that it was not exceeded, customers will also be notified). Notification will include the AANR for the prior fiscal year, the DDC Amount, the calculation of the DDC Amount, and the estimated resulting Power Customer DDC Percentage for each applicable rate schedule. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available for review at BPA upon request. The notice shall also contain the tentative schedule for the remainder of the DDC implementation process.

- (1) On or about March 1 of any of the fiscal years 2002-2006 in which the AANR exceeds the DDC Threshold, the Administrator will post the Five-Year Forecast on BPA's World Wide Web site and will propose to distribute or not distribute dividends. During March, BPA will conduct a public review and comment process on the proposal.
- (2) On or about April 15 of any of the fiscal years 2002-2006 in which the AANR exceeds the DDC Threshold, BPA shall notify customers to which the DDC applies of the decision on the proposal, the final calculation of the DDC Amount, the allocation of the DDC Amount, and, if applicable, the resulting level of the Power Customer DDC Percentage to be applied to each applicable firm power rate schedule.

I. 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 kilowatthours, than the underlying load would have used.

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

The total amount of Excess Within-Day Factoring Charge during the HLH's of the month shall be billed the greater of:

- a. Five (5) mills/kWh;
- b. Among all HLH periods of the billing month, the maximum within-day difference between the highest hourly HLH California ISO Supplemental Energy price (NP15) and the lowest hourly HLH California ISO Supplemental Energy price (NP15).

The total amount of Excess Within-Day Factoring Charge during the LLH's of the month shall be billed the greater of:

- a. Five (5) mills/kWh;
- b. Among all LLH periods of the billing month, the maximum within-day difference between the highest hourly LLH California ISO Supplemental Energy price (NP15) and the lowest hourly LLH California ISO 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, such as the California PX (NW1 or NW 3), 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.

The Excess Within-Month Factoring during the HLH's of the month shall be billed the greater of:

- a. Five (5) mills/kWh.
- b. The highest peak 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.

- c. The highest average HLH California ISO Supplemental Energy price (NP15) (average of hours 7 through 22, excluding Sundays) during the month LESS the lowest average HLH California ISO Supplemental Energy price (NP15) for the same period.

The Excess Within-Month Factoring during the LLH's of the month shall be billed the greater of:

- a. Five (5) mills/kWh.
- b. The highest offpeak DJ Mid-C Index price for firm power during the month LESS the lowest offpeak DJ Mid-C Index price for firm power;
- c. The highest average LLH California ISO Supplemental Energy price (NP15) (average of hours 1 through 6, and 23, and 24 Monday through Saturday; average of hours 1 through 24 Sunday) during the month LESS the lowest average LLH California ISO Supplemental Energy price (NP15) for the same month in the same time period.

In the event that the index for ISO 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, such as the California PX (NW1 or NW3), at a hub at which Northwest parties can trade.

J. Flexible IP Rate Option

The Flexible IP rate option will be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option for all five years of the rate period. The charges and billing factors under this option will be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying the following condition:

Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible IP 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 IP rate schedule Section II been applied to the same sales.

The Flexible IP rate contract may establish a limit on the amount of power purchased at the Flexible IP rate. In this case, purchases beyond the contractual limit will be billed at the Demand and Energy charges specified in the IP rate schedule Section II unless such power would be charged as an Unauthorized Increase.

Risk Adjustments: Credit risk associated with individual customers will be a factor in establishing any flexible rate option. Creditworthiness will be determined by BPA consistent with prevailing business standards, and applied consistently to each customer. Such credit risks will be dealt with through a "margin deposit," expense charge, built into the rates, or other methods acceptable to BPA.

K. Flexible NR Rate Option

The Flexible NR rate option will be offered at BPA's discretion to purchasers who make a contractual commitment 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 Net Present Value Revenues: Forecasted 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 and SUMY, if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

The Flexible NR rate option is only available for development of an energy rate that is stepped up in FY 2005 and 2006.

L. Flexible PF Rate Option

The Flexible PF rate option will be offered at BPA's discretion to purchasers who make a contractual commitment 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 Net Present Value Revenues: Forecasted 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, and SUMY if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

The Flexible PF rate option is only available for development of an energy rate that is stepped up in FY 2005 and 2006.

M. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from zero to \$40/megawatthour (MWh) that a customer elects to pay BPA to ensure that BPA is producing some system power from Environmentally Preferred Power (EPP) resources. The GEP is the difference between the customer's applicable average annual energy charge under the PF-02, RL-02, NR-02, and IP-02 rates and the total cost of the EPP resource selected by the customer. The GEP is applied to the number of EPP MWhs that the customer has elected to purchase. BPA guarantees the customer paying the premium that BPA will produce an amount of EPP 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.

The costs to be considered in determining the applicable GEP include, but are not limited to:

- Costs of existing EPP resources, over and above the cost of BPA system resources.
- Costs of new EPP resources, over and above the cost of BPA system resources.
- Costs of BPA system resources.
- Endorsement fees for specific EPP resources.
- Market purchases of EPP resources.
- Transmission and other services required to integrate EPP resources into the BPA system.

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 premium will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation during the Subscription window. The charge will not exceed \$40 per MWh and may be as low as zero. The premium will be zero if the unit cost of the GEP resource(s) dedicated to the customer is equal to, or less than, the energy charge of the applicable rate. The premium will be equal to the average unit cost of the GEP resource(s) minus the applicable average PF-02, RL-02, NR-02, and IP-02 energy charge.

b. Determination of Individual Customer GEP

- (1) During the Subscription window, 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 kilowatthour (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 and Renewables Discount 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:

$$(\text{EPP amount}) \text{ kWh} * \text{GEP mills/kWh} = \$\text{XXXXXX}$$

N. Guaranteed Delivery Charge (NF only)

A surcharge of 2.00 mills/kWh of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the NF Standard rate or Market Expansion rate.

O. Industrial Firm Power Targeted Adjustment Charge (IPTAC)

1. Availability

The Industrial Firm Power Targeted Adjustment Charge (IPTAC) pertains to the IP rate schedule. The IPTAC will be applied to Firm Power requirements service of DSIs who take service from a combination of Federal inventory and power purchased from the market during the 2002 rate period.

The maximum total requirements service the IPTAC will be developed for, and applied to, is 1,440 aMW (flat, annual block). The total inventory used to provide this requirement service will be composed of 990 aMW from Federal inventory and 450 aMW of market purchases.

There will be two rates for the IPTAC product. 1210 aMW will be sold at \$23.50 per MWh, and 230 aMW sold at \$25 per MWh.

P. Low Density Discount

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 Priority Firm Power, New Resources Firm Power and Residential Load Firm Power service: (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 Kilowatthour/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 on 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 an additional billed consumer.

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 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 Pacific Northwest (PNW). For Purchaser's 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 pieces of 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 the Purchaser's average cost of BPA power purchases under the applicable rate for the qualifying period by at least 10 percent. For CY 2001, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable 1996 rate for the first nine months and under the applicable 2002 rate for the last three months. For CY 2002 and beyond, the Purchaser's average cost of BPA power purchases under the applicable rate shall be under the applicable rate for all 12 months;
- 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, 2001, 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 C. The discount shall not exceed 7 percent.

Table C
LDD Percentage Discount Table

<i>Percentage Discount</i>	<i>Applicable Range for kWh/Investment (K/I) Ratio</i>	<i>Applicable Range for Consumers/Mile (C/M) Ratio</i>
0.0%	$35.0 \leq X$	$12.0 \leq X$
0.5%	$31.5 \leq X < 35.0$	$10.8 \leq X < 12.0$
1.0%	$28.0 \leq X < 31.5$	$9.6 \leq X < 10.83$
1.5%	$24.5 \leq X < 28.0$	$8.4 \leq X < 9.6$
2.0%	$21.0 \leq X < 24.5$	$7.2 \leq X < 8.4$
2.5%	$17.5 \leq X < 21.0$	$6.0 \leq X < 7.2$
3.0%	$14.0 \leq X < 17.5$	$4.8 \leq X < 6.0$
3.5%	$10.5 \leq X < 14.0$	$3.6 \leq X < 4.8$
4.0%	$7.0 \leq X < 10.5$	$2.4 \leq X < 3.6$
4.5%	$3.5 \leq X < 7.0$	$1.2 \leq X < 2.4$
5.0%	$X \leq 3.5$	$X < 1.2$

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 1/2 percent if the calculated discount exceeds the existing discount; or
- b. the existing discount minus 1/2 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. Benefits Legislation Exclusion

If the Federal government or a State, or local government adopt(s) a law, regulation or other provision that establishes benefits for low density and/or rural electric systems that are similar to benefits provided by BPA's LDD, then the Purchaser's service territory within that jurisdiction shall no longer be eligible to receive the LDD. The effective date for discontinuation of the LDD and the Phase-Out Adjustment shall be the implementation date of the jurisdiction's benefits provision legislation. BPA will evaluate new provisions and determine, in BPA's judgment, whether they provide benefits similar to the LDD. If BPA

concludes that the benefits are similar, BPA will conduct a public comment process before issuing a final decision.

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.

Q. Rate Melding

BPA's rate proposal allows the customers more than one rate choice. Separately tracking and administering the customer's 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.*, Cost Recovery Adjustment Clause), or a significant change in the loads applicable to the rates occurs.

R. Slice True-Up Adjustment

By March 31 of each year, BPA will calculate the final true-up for the previous fiscal year based on the difference between the Slice Revenue Requirement's audited actual expenses (and credits) and those expenses (and credits) forecasted in the 2002 rate case (except for the Inventory Solution which is billed based on the estimate from the 2002 rate case). This true-up will be the True-Up Adjustment Charge and will be applied to the customer's May bill. In addition, an interim true-up adjustment procedure to allow for an intermediate true-up prior to March 31, will be developed in the power sales contracts with the customers.

Table D

BASIS FOR SLICE TRUE-UP ADJUSTMENT CHARGE

Generation Expenses (\$thousands)		2002		2003		2004		2005		2006		Rev Req
		Total	Slice	Total	Slice	Total	Slice	Total	Slice	Total	Slice	
1	Operating Expenses	27,600	27,600	17,550	17,550	15,450	15,450	13,250	13,250	11,600	11,600	85,450
2	CSRS Pension Expense	16,000	16,000	15,700	15,700	8,800	8,800	6,800	6,800	5,000	5,000	52,300
3	Power Marketing	52,000	50,000	52,000	50,000	52,000	50,000	52,000	50,000	52,000	50,000	250,000
4	Wheeling (GTAs)	20,900	20,900	12,800	12,800	12,100	12,100	12,800	12,800	12,700	12,700	71,300
5	Power Scheduling	154,900	1,990	151,402	2,050	160,205	2,111	169,125	2,174	176,294	2,240	10,565
6	ST Purchased Power/Upstr Benefits	-	-	-	-	-	-	-	-	-	-	-
7	PNCA Interchange	2,964	2,964	2,950	2,950	3,050	3,050	3,050	3,050	3,150	3,150	15,163
8	Generation Oversight	29,351	29,351	27,763	27,763	28,063	28,063	28,463	28,463	28,763	28,763	142,401
9	Conservation & Consumer Services (incl EE)	131,700	131,700	138,000	138,000	140,100	140,100	142,900	142,900	144,400	144,400	697,100
10	Fish & Wildlife	17,350	17,350	16,650	16,650	16,650	16,650	16,650	16,650	16,650	16,650	83,950
11	Administrative & Support Services	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	5,100	25,500
12	Planning Council	108,000	108,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	112,000	556,000
13	Corps of Engineers O&M	15,400	15,400	16,197	16,197	16,995	16,995	17,892	17,892	18,789	18,789	85,273
14	U.S. Fish & Wildlife O&M	47,000	47,000	48,300	48,300	48,300	48,300	48,300	48,300	48,300	48,300	240,200
15	Bureau of Reclamation O&M	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	80,000
16	Colville Settlement	20,302	20,302	20,117	20,117	19,968	19,968	19,885	19,885	19,836	19,836	100,109
17	Renewable Projects	400	400	384	384	384	384	384	384	384	384	1,936
18	WNP-1 O&M	154,094	154,094	163,824	163,824	170,724	170,724	173,824	173,824	179,824	179,824	842,290
19	WNP-2 O&M/Capital Requirements	3,086	3,086	3,169	3,169	3,169	3,169	3,169	3,169	3,169	3,169	15,762
20	WNP-3 O&M	9,600	9,600	4,200	4,200	2,600	2,600	2,600	2,600	2,600	2,600	21,600
21	Trojan Decommissioning	151,941	41,682	157,689	45,309	165,524	54,947	183,763	55,003	164,130	55,061	251,982
22	Between Business Line Expense 1/	26,805	26,805	27,245	27,245	27,682	27,682	28,279	28,279	28,763	28,763	138,774
23	LT Power Purchases	-	-	-	-	-	-	-	-	-	-	-
24	Rate Pledge Adjustment	1,010,492	745,303	1,009,040	745,308	1,024,864	754,193	1,036,234	758,523	1,049,452	764,329	3,767,655
25	System Operation & Maintenance	177,704	177,704	167,856	167,856	174,623	174,623	167,910	167,910	179,992	179,992	868,085
26	WNP-1	197,442	197,442	244,980	244,980	233,624	233,624	187,825	187,825	211,976	211,976	1,075,847
27	WNP-2	153,720	153,720	152,993	152,993	149,232	149,232	149,480	149,480	147,838	147,838	753,261
28	WNP-3	9,947	9,947	9,954	9,954	9,964	9,964	9,989	9,989	10,009	10,009	49,863
29	Trojan	5,578	5,578	5,577	5,577	5,577	5,577	5,577	5,577	5,577	5,577	27,886
30	Conservation Financing	2,880	2,880	2,880	2,880	2,880	2,880	2,880	2,880	2,880	2,880	14,399
31	Renewable Projects	15,917	15,917	15,916	15,916	15,920	15,920	15,933	15,933	15,935	15,935	79,621
32	LT Power Purchases	563,187	563,187	600,156	600,156	591,820	591,820	539,594	539,594	574,205	574,205	2,868,962
33	Total Non-Fed. Projects Debt Service	95,288	95,288	97,910	97,910	100,170	100,170	102,215	102,215	104,164	104,164	499,747
34	Depreciation	80,002	80,002	78,321	78,321	71,755	71,755	69,468	69,468	64,950	64,950	364,494
35	Amort.: Conservation & Fish & Wildlife	176,290	176,290	176,231	176,231	171,925	171,925	171,681	171,681	169,114	169,114	864,241
36	Total Federal Projects Depreciation	-	-	-	-	-	-	-	-	-	-	-
37	IOU Payment (in lieu of Residential Exchange)	1,760,119	1,483,780	1,785,427	1,521,685	1,788,609	1,517,938	1,747,509	1,469,798	1,792,770	1,507,647	7,500,858
38	Total Operating Expenses	214,665	214,665	213,607	213,607	219,193	219,193	224,550	224,550	221,653	221,653	1,093,568
39	Net Federal Interest Expense	1,974,784	1,698,446	1,998,934	1,735,202	2,007,802	1,737,131	1,972,059	1,694,348	2,014,423	1,729,300	8,594,426
40	Total Operating & Net Interest Expenses	-	-	-	-	-	-	-	-	-	-	-
41	Miscellaneous expenses 2/	-	-	-	-	-	-	-	-	-	-	-
42	TOTAL ACCRUED EXPENSES FOR SLICE TRUE-UP	1,698,446		1,735,202		1,737,131		1,694,348		1,729,300		8,594,426
43	Revenue Credits											
44	Ancillary and Reserve Service Revs.	87,336		87,233		88,072		88,023		87,945		438,609
45	PBL PF Trans. Pass-Through Revs.	14,190		14,247		14,304		14,361		14,418		71,520
46	Canadian Entitlement Credit	1,000		1,000		1,000		1,000		1,000		5,000
47	COE & USBR Project Revenues	8,100		8,100		8,100		8,100		8,100		40,500
48	4(h)(10)(c)	86,523		90,187		88,258		89,687		92,149		446,804
49	Colville Credit	4,600		4,600		4,600		4,600		4,600		23,000
50	FCCF	43,559		27,132		20,387		10,600		6,492		108,170
51	Sup/Ent Cap; Irr. Pump	838		707		471		471		471		3,059
52	Energy Efficiency Revenues	13,046		13,345		13,345		13,345		13,345		66,426
53	Property Trnfrs & Misc.	3,416		3,416		3,416		3,416		3,416		17,080
54	Miscellaneous credits 3/	-		-		-		-		-		-
55	Total Revenue Credits	262,708		249,967		241,953		233,603		231,936		1,220,168

1/ Includes BPA Generation-Integration (under Ancillary Services), PF Transmission pass-through, PNCA and NTS Transmission, CEA Transmission, and Between Business Line Expenses.

2/ Includes Slice administrative expenses, WNP-2 economic displacement charges, conservation & renewables surcharge expenses, etc. The amounts associated with these expenses will not be determined until they actually are incurred. In some years, the amount for any of these expenses could be zero. In addition, Slice administrative expenses are shared equally amongst Slice participants.

3/ Includes potential applicable revenue credits, the type and amount of which will be determined as they are accrued.

S. Stepped Up Multiyear Block (SUMY)

The SUMY Block charge applies to Block purchases if the annual amounts increase (i.e., step up) over multiple years of a purchase commitment term due to increases in customer net requirement which are not subject to a Targeted Adjustment Charge (TAC).

The cost for the SUMY Block service is the difference between PF-02 rates and the AURORA On- and Off- Peak market price forecast in the final rate proposal.

The starting basis for computing the SUMY Block quantities will be the purchaser's subscribed block amount for the period October 2001 through September 2002. Costs will be computed for 24 monthly blocks (12 HLH and 12 LLH) for each year of the rate period. Each year's monthly amount above the base year's monthly amount is the stepped up quantity. Total cost is the sum of each month's HLH and LLH stepped up quantities times each month's HLH and LLH costs.

The SUMY charge is the total cost of the SUMY Block service divided by the total Block energy purchase including stepped up amounts. The charge is in addition to the PF and NR energy and demand rates that the customer will pay for these power purchases.

Formula for Calculating a Charge for SUMY Block Service:

- Step 1: Determine HLH MWh of SUMY Block.
$$\text{October 2002 HLH Block} - \text{October 2001 HLH Block} = \text{HLH MWh of SUMY Block for October 2002}$$
- Step 2: Determine LLH MWh of SUMY Block.
$$\text{October 2002 LLH Block} - \text{October 2001 LLH Block} = \text{LLH MWh of SUMY Block for October 2002}$$
- Step 3: Determine Cost of HLH SUMY Block service.
$$\text{HLH MWh of SUMY Block} * (\text{Aurora October 2002 On-Peak Market Price} - \text{October 2002 PF HLH energy and demand rate}) = \text{Total Cost of October 2002 HLH SUMY Block service.}$$
- Step 4: Determine Cost of LLH SUMY Block service.
$$\text{LLH MWh of SUMY Block} * (\text{Aurora October 2002 Off-Peak Market Price} - \text{October 2002 PF LLH energy rate}) = \text{Total Cost of October 2002 LLH SUMY Block service.}$$

- Step 5: Determine Cost for all months of the rate period by repeating Steps 1-4 for each month of the remaining purchase period always calculating the MWh difference from the first year and corresponding month. Calculate the price difference using that year's and month's market price and PF rate.
- Step 6: Custom Charge: Divide the Net Present Value (NPV) of the stream of costs derived from Steps 1-5 by the NPV of the total block purchase including SUMY Block in MWh for the five-year period. The NPV uses a 6.8 percent discount rate and is present valued to October 2001.
- Step 7: Billing Determinant: Custom charge is applied to each MWh of block purchase including the SUMY Block amounts.

T. Supplemental Contingency Reserves Adjustment (SCRA)

The energy charges stated in the IP-02 rate schedule will be adjusted to reflect the negotiated SCRA adjustment. PBL 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. PBL has established a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of reserves provided. The maximum amount PBL may pay for Supplemental Reserves from a DSI is capped at \$5.92/kW-mo.

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 PBL must be consistent with NERC, WSCC, and NWPP 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;
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 PBL may pay the maximum value for Supplemental Reserves:

1. the extent to which PBL 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;
2. whether there are limitations on the number of times or total minutes the reserves may be utilized.

U. Targeted Adjustment Charge

1. Availability

The Targeted Adjustment Charge (TAC) pertains to the PF rate schedule, except for PF exchange program and PF exchange Subscription rates. 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 the Subscription window closes.

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.

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 PF-02. 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 Subscription, the public agency customer will receive through assignment the right to the IOUs power and/or financial benefits applicable to the annexed load. BPA will deliver the same amount of firm power that was assigned by the IOU to the annexing public agency customer at the PF-02 rate. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the power assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the Customer's contract or until 2006, whichever occurs first. For five-year contracts that guarantee rates for a multitude of periods (for example, contracts that have both three-year and five-year components) the TAC applies until the end of the five-year rate period. If a new public requests service, the TAC, if any, must apply until 2006.

If a PF Preference customer is serving a portion of its load with a certifiable renewable resource eligible for the C&R Discount, or contract purchases of certified renewable resource power eligible for the C&R Discount for a period less than the term of the customer's BPA requirements firm power contract, then

the customer may request, during the 2002 to 2006 rate period, requirements firm power service for such load at the end of the specified contract period at PF Preference (PF-02) 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 2002 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:

$$\text{TAC} = [(\text{Incr } \$ * \text{Incr Amt}) - (\text{Rate } \$ * \text{Incr Amt})] / \text{TAC Amt}$$

where:

- TAC Amt = The amount of load subject to the TAC, determined monthly.
- Rate \$ = The monthly PF energy rate shown in the applicable rate schedule.
- Inventory Amt = Amount of energy in inventory available to serve this load based on average annual Federal system firm resource capability, estimated using critical water excluding balancing purchases and purchases for system augmentation, from the 2002 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 such as, but not limited to, the California ISO or the California PX.
- 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).
- Incr \$ is greater than Rate \$ (If Incr \$ is less than Rate \$, the TAC is 0 mills/kWh).

TAC is the monthly rate adjustment in 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 methods:

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

V. Unauthorized Increase 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 ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW1 (COB); or
- c. The sum of hourly California ISO Spinning Reserve Capacity prices for all HLHs in the month, at path NW3 (NOB).

In the event that the hourly California ISO 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;
- 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, 2001, and September 30, 2006.

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. One hundred (100) mills/kWh; or
- b. for the month in question, the greater of:
 - (1) the highest diurnal DJ Mid-C Index price for firm power; or

- (2) the highest hourly ISO California Supplemental Energy price (NP15).

In the event that either the ISO California 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 California PX, NW1 (COB);
- (2) the highest price experienced for the month at the California PX, 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, 2001, and September 30, 2006.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By the Power Business Line of BPA

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. 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-02), New Resources Firm Power (NR-02), and Firm Power Products and Services (FPS-96), rate schedules.

Such power is not available for the PF Exchange Program rate, the PF Exchange Subscription rate, and the Residential Load 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.

6. 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

7. Customer System Peak (CSP)

Customer System Peak (CSP) is the largest measured HLH Total Retail Load (TRL) amount in kilowatts for the billing period.

8. 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.

9. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (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.

10. 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.

11. New Resource Firm Power

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

- a. for any New Large Single Load (NLSL); and
- b. for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

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

New Resource Firm Power 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. New Resource Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and the NWPP.

12. Nonfirm Energy

Nonfirm Energy is energy that is supplied or made available by BPA to a Purchaser under an arrangement that does not have the guaranteed continuous availability feature of Firm Power. Nonfirm energy is sold primarily under the Nonfirm Energy rate schedule, NF-02. Nonfirm energy also may be supplied under the NF-02 rate schedule to the Western Systems Power Pool (WSPP) subject to terms and conditions agreed upon by the members participating in the WSPP and in accordance with BPA policy for such arrangements. Nonfirm Energy that has been purchased under a guarantee provision in the Nonfirm Energy rate schedule shall be provided to the Purchaser in accordance with the provisions of that schedule and the power sales contract if applicable. BPA may make Nonfirm Energy available to purchasers both inside and outside the United States.

13. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or 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 Priority Firm Power pursuant to their Residential Exchange contracts with BPA. Priority Firm Power is not available to serve NLSLs. Deliveries of Priority Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

Priority Firm Power 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. Priority Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and NWPP.

14. Regulation and Frequency Response

Regulation and frequency response is the generating capacity of a power system that is immediately responsive to AGC control 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 Federal system resources over the year. 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.

B. Definition of Rate Schedule Terms

1. 2002 Contract

A 2002 contract is a contract for service in the FY 2002 through 2006 rate period that is signed after January 1, 1999.

2. 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.

3. 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.

4. 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.

5. California Independent System Operator (California ISO)

The FERC regulated control area operator of the ISO 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 ISO has no affiliation with any market participant.

6. California ISO Spinning Reserve Capacity

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

7. California ISO 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 California ISO at least 30 minutes before the commencement of the settlement period.

8. California Power Exchange (California PX)

An independent agency responsible for conducting an auction for the generators seeking to sell energy and for loads which are not otherwise being served by bilateral contracts. The California PX is responsible for scheduling generation in its scheduling (*e.g.*, day-ahead) markets, for determining hourly market clearing prices for its market, and for settlement and billing for suppliers and Utility Distribution Company's (UDC) using its market.

9. 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.

10. Contract Energy

Contract Energy is the maximum number of kilowatthours 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.

11. 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 power flow across interchange boundaries to other Control Areas.

12. Decremental Cost

Unless otherwise specified in a contractual arrangement, Decremental Cost as applied to Nonfirm Energy transactions is defined as:

- a. All identifiable costs (expressed in mills/kWh) associated with the use of a displaceable thermal resource or end-use load with alternate fuel source to serve a purchaser's load that the purchaser is able to avoid by purchasing power from BPA, rather than generating the power itself or using an alternate fuel source; or
- b. All identifiable costs (expressed in mills/kWh) to serve the load of a displaceable purchase of energy that the purchaser is able to avoid by choosing not to make the alternate energy purchase.

All identifiable costs as used in the above definition may be reduced to reflect costs of purchasing BPA energy such as transmission costs, losses, or loopflow constraints that are agreed to by BPA and the Purchaser.

13. Delivering Party

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

14. 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.

15. Discount Period

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

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

Peak and offpeak price indexes for sale of firm and nonfirm power traded at the Mid-Columbia Bus.

17. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatthours).

18. Energy Entitlement

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

19. 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.

20. Firm Power (PF-02, IP-02, NR-02, RL-02)

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.

21. Full Service Customer

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

22. Generation System Peak

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

23. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period hour ending 7 a.m. to the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

24. Inventory Solution Costs

Costs associated with BPA's potential actions to supplement the capability of the Federal System Resources, as a result of BPA's Subscription process. It is currently not known whether an Inventory Solution will be necessary, or what form the Inventory Solution will take.

25. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the offpeak period hour ending 11 p.m. to 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).

26. 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.

27. 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.

28. 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.

29. Metered Energy

The Metered Energy for a purchaser shall be the number of kilowatthours 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.

30. Mid-Columbia Bus (Mid-C Bus)

The switchyards associated with five non-Federal hydroelectric projects, including Rocky Reach, Priest Rapids, Wanapum, Douglas, and McKenzie. The following Federal switchyards which are operated by BPA and interconnected with the non-Federal switchyards are also included: Valhalla, Columbia, Midway, Sickler, and Vantage.

31. 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.

32. NP15

The portion of the California ISO's control area north of transmission path 15.

33. NW1 (California-Oregon Border)

California PX and California ISO designation for delivery at COB (Captain Jack/Malin).

34. NW3 (Nevada-Oregon Border)

California PX and California ISO designation for delivery at NOB.

35. Partial Service Customer

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

36. Point of Delivery (POD)

A Point of Delivery 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 could be located at the change of ownership point on a transmission line.

37. 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 could be located at some other interconnection point to receive system power from the customer.

38. Point of Interconnection (POI)

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

39. Points of Metering (POM)

The Points of Metering (POM) shall be those points specified in the contract at which TRL and Metered Amounts are measured.

40. 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.

41. Purchaser

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

42. Receiving Party

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

43. Retail Access

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

44. Scheduled Demand

For purposes of applying the rates herein to applicable purchases by the Purchaser, the Scheduled Demand in kilowatts 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.

45. Scheduled Energy

For purposes of applying the rates herein to applicable purchases by the Purchaser, Scheduled Energy in kilowatthours 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.

46. Slice Administrative Costs

All overhead costs incurred by BPA that are attributable to the implementation of the Slice product.

47. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of all the line items in BPA's PBL revenue requirement as identified in all of the PBL's rate cases that are effective during the term of the Slice Purchaser's contract except for the following items: (1) transmission costs (other than those associated with the fulfillment of System Obligations); (2) power purchase costs (with the exception of those net costs incurred as part of the "Inventory Solution"); and (3) planned net revenues for risk.

See Table E for Slice Product Costing Table.

Table E

SLICE PRODUCT COSTING TABLE

PBL Costs (\$000)		2002	2003	2004	2005	2006	TOTAL
GENERATION COSTS							
1	Federal Base System						
2	Hydro	\$ 447,800	\$ 455,373	\$ 468,464	\$ 479,149	\$ 483,041	\$ 2,333,825
3	Fish and Wildlife	\$ 159,425	\$ 167,905	\$ 172,350	\$ 176,722	\$ 179,102	\$ 855,504
4	Trojan	\$ 19,547	\$ 14,154	\$ 12,564	\$ 12,589	\$ 12,609	\$ 71,463
5	WNP #1	\$ 178,104	\$ 168,240	\$ 175,007	\$ 168,294	\$ 180,376	\$ 870,021
6	WNP #2	\$ 351,536	\$ 408,804	\$ 404,348	\$ 361,649	\$ 391,800	\$ 1,918,137
7	WNP #3	\$ 153,720	\$ 152,993	\$ 149,232	\$ 149,480	\$ 147,836	\$ 753,261
8	Total	\$ 1,310,131	\$ 1,367,469	\$ 1,381,965	\$ 1,347,883	\$ 1,394,764	\$ 6,802,211
9							
10	New Resources						
11	Idaho Falls	\$ 3,740	\$ 3,737	\$ 3,744	\$ 3,754	\$ 3,754	\$ 18,729
12	Cowlitz	\$ 14,914	\$ 14,987	\$ 15,051	\$ 15,123	\$ 15,196	\$ 75,271
13	Firm Purchased Power	\$ 17,723	\$ 17,953	\$ 18,187	\$ 18,435	\$ 18,681	\$ 90,978
14	Other Acquisitions						
15	Total	\$ 36,377	\$ 36,677	\$ 36,982	\$ 37,312	\$ 37,631	\$ 184,978
16							
17	Legacy Conservation	\$ 131,799	\$ 126,452	\$ 114,284	\$ 109,498	\$ 101,240	\$ 583,272
18	Energy Services Business	\$ 11,349	\$ 11,353	\$ 11,321	\$ 11,261	\$ 11,227	\$ 56,511
19	Other Generation Costs						
20	BPA Programs	\$ 118,043	\$ 98,774	\$ 88,465	\$ 84,222	\$ 80,209	\$ 469,713
21	Other						
22	WNP #3 Plant	\$ 3,086	\$ 3,169	\$ 3,169	\$ 3,169	\$ 3,169	\$ 15,762
23	Total	\$ 121,129	\$ 101,943	\$ 91,634	\$ 87,391	\$ 83,378	\$ 485,475
24							
25	COSA Table Subtotal	\$ 1,610,784	\$ 1,643,893	\$ 1,636,185	\$ 1,593,345	\$ 1,628,240	\$ 8,112,447
26							
27	CEA Transmission Costs	\$ 13,514	\$ 17,105	\$ 26,685	\$ 26,685	\$ 26,685	\$ 110,675
28	Ancillary and Reserve Service Costs	\$ 8,000	\$ 8,000	\$ 8,000	\$ 8,000	\$ 8,000	\$ 40,000
29	PBL PF Trans. Pass-Through Costs	\$ 14,190	\$ 14,247	\$ 14,304	\$ 14,361	\$ 14,418	\$ 71,520
30	PNCA & NTS Transmission Costs	\$ 1,957	\$ 1,957	\$ 1,957	\$ 1,957	\$ 1,957	\$ 9,785
31	General Transfer Agreement Costs	\$ 50,000	\$ 50,000	\$ 50,000	\$ 50,000	\$ 50,000	\$ 250,000
32							
33	REVENUE REQUIREMENT CHECK	\$ 1,698,445	\$ 1,735,202	\$ 1,737,131	\$ 1,694,348	\$ 1,729,300	\$ 8,594,426
34							
35	PF Conservation and Renewables Credit Costs						\$ 96,416
36	IP Conservation and Renewables Credit Costs						\$ 21,693
37	RL Conservation and Renewables Credit Costs						\$ 21,900
38	LDD	\$ 14,000	\$ 14,000	\$ 14,000	\$ 14,000	\$ 14,000	\$ 70,000
39	S & I Rate Mitigation Costs	\$ 4,000	\$ 4,000	\$ 4,000	\$ 4,000	\$ 4,000	\$ 20,000
40	Non-COSA Table Subtotal						\$ 230,009
41							
42	Total PBL Revenue Requirement						\$ 8,824,435
43							
44	Revenue Credits (\$000)						
45	Ancillary and Reserve Service Revs.	\$ 87,336	\$ 87,233	\$ 88,072	\$ 88,023	\$ 87,945	\$ 438,610
46	PBL PF Trans. Pass-Through Revs.	\$ 14,190	\$ 14,247	\$ 14,304	\$ 14,361	\$ 14,418	\$ 71,520
47	Canadian Entitlement Credit	\$ 1,000	\$ 1,000	\$ 1,000	\$ 1,000	\$ 1,000	\$ 5,000
48							
49	COE & USBR Project Revenues	\$ 8,100	\$ 8,100	\$ 8,100	\$ 8,100	\$ 8,100	\$ 40,500
50	4(h)(10)(c)	\$ 86,523	\$ 90,187	\$ 88,258	\$ 89,687	\$ 92,149	\$ 446,804
51	Colville Credit	\$ 4,600	\$ 4,600	\$ 4,600	\$ 4,600	\$ 4,600	\$ 23,000
52	FCCF	\$ 43,559	\$ 27,132	\$ 20,387	\$ 10,600	\$ 6,492	\$ 108,170
53	Sup/Ent Cap; Irr. Pump	\$ 938	\$ 707	\$ 471	\$ 471	\$ 471	\$ 3,059
54	Energy Efficiency Revenues	\$ 13,046	\$ 13,345	\$ 13,345	\$ 13,345	\$ 13,345	\$ 66,426
55	Property Tmfrs & Misc.	\$ 3,416	\$ 3,416	\$ 3,416	\$ 3,416	\$ 3,416	\$ 17,080
56							
57	Total Revenue Credits						\$ 1,220,169
58							
59	Power Revenues Needed						\$ 7,604,267
60							
61	Firm System Augmentation (1112 aMWs on avera	\$ 252,064	\$ 290,218	\$ 253,541	\$ 292,433	\$ 279,879	\$ 1,368,135
62	DSI Augmentation (450 aMWs)	\$ 110,770	\$ 110,770	\$ 110,770	\$ 110,770	\$ 110,770	\$ 553,851
63							
64	Subscription Settlement Costs (800 aMWs in \$s)	\$ 54,310	\$ 54,310	\$ 54,310	\$ 54,310	\$ 54,310	\$ 271,550
65	Total Cost of Inventory Solution	\$ 417,144	\$ 455,298	\$ 418,621	\$ 457,513	\$ 444,959	\$ 2,193,536
66							
67	Revenue 1112 aMWs flat, 450 aMWs to DSIs	\$ (301,889)	\$ (301,889)	\$ (301,889)	\$ (301,889)	\$ (301,889)	\$ (1,509,444)
68	Net Cost of Inventory Solution	\$ 115,255	\$ 153,409	\$ 116,732	\$ 155,625	\$ 143,071	\$ 684,092
69							
70							
71	Annual Slice Revenue Requirement	\$ 1,657,672					
72	Monthly Slice Revenue Requirement	\$ 138,139					
73	One Percent of Monthly Requirement	\$ 1,381.39					
74							

48. Subscription

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

49. Subscription Contract

See 2002 Contract.

50. System Obligations

System Obligations include, but are not limited to, the transmission costs associated with the return of the Canadian Entitlement, and transactions related to the Pacific Northwest Coordination Agreement, Mid-Columbia Hourly Coordination, and the Canadian Non-Treaty Storage Agreement.

51. Total Plant Load

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.

52. Total Retail Load (TRL)

Total Retail Load 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, Total Retail Load is called Total Plant Load.

53. Utility Distribution Company

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

BPA'S New 1996
GENERAL RATE SCHEDULE PROVISIONS
FOR POWER RATES

A. Targeted Adjustment Charge for Uncommitted Loads

1. Availability

The Targeted Adjustment Charge for Uncommitted Loads (TACUL) pertains to the PF rate schedule. The TACUL applies after December 7, 2000, to purchases to serve customer loads that were uncommitted during the 1996 rate case which are returned to BPA firm power requirements service during a period prior to FY 2002. Customers subject to the TACUL are those that reduced their purchases from BPA by adding firm resources to serve load under: (1) 1981 power sales contracts that expire on or before July 31, 2001, as may be amended; (2) Amendatory Agreement No. 7 (AA7) to the 1981 power sales contracts, or new "1996" power sales contracts where the customer provides BPA notice after December 7, 1998, consistent with the terms of the customer's power sales contract, for requirements service for the period prior to FY 2002. This charge will be in effect through September 30, 2001.

This rate schedule amends the PF-96 rate schedule, which went into effect October 1, 1996.

2. Energy Charge

The TACUL is a monthly mills/kWh adjustment to the HLH and LLH energy rates specified in the 1996 rate schedule, and is applied to that portion of the customer's load that is subject to the TACUL. The TACUL rate adjustment will be established based on the following formula:

$$\text{TACUL} = [(\text{Incr } \$ * \text{Incr Amt}) - (\text{Rate } \$ * \text{Incr Amt})] / \text{TACUL Amt}$$

where:

TACUL Amt = The amount of load subject to the TACUL, determined monthly.

Rate \$ = The monthly PF energy rate shown in the applicable rate schedule.

Inventory Amt = Amount of energy available to serve this load based on an annual energy Federal system firm resource capability as defined in the Loads and Resources Study, and updated if BPA determines that is necessary.

Incr \$ = Monthly cost to BPA, plus a handling fee, of incremental power for HLH and LLH expressed in

mills/kWh (see below). These costs also may include where applicable, wheeling, ancillary, and other charges BPA may incur in purchasing power from other entities such as, but not limited to, the California ISO or the California PX.

Incr Amt = Amount of incremental power required, determined monthly and defined as the TACUL Amt minus the Inventory Amt. (If there is no available Inventory Amt, the Incr Amt will equal the TACUL Amt).

Incr \$ is greater than Rate \$ (If Incr \$ is less than Rate \$, the TACUL is 0 mills/kWh).

TACUL is the monthly rate adjustment in 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 methods:

- a. BPA will establish the price based on BPA's monthly cost to purchase the incremental load by purchases of resources at market, or the monthly cost of BPA recallable power contracts, averaged, whichever is less.
- b. A price plus handling fee calculated based on the following index.

BPA will calculate the price per month for HLH and LLH, based on an index calculated according to the following:

Price of HLH = $\frac{1}{3}$ HLH (DJ Mid C) + $\frac{1}{3}$ HLH (California PX) + $\frac{1}{3}$ (NYMEX Mid C)

Price of LLH = $\frac{1}{2}$ LLH (DJ Mid C) + $\frac{1}{2}$ LLH (PX)
where the California PX basis is adjusted to DJ Mid C

where:

DJ Mid C = Dow Jones Firm On-peak (HLH) and Firm Off-peak (LLH) Mid-Columbia Electricity Price Index

California PX = California Power Exchange Day-Ahead Zonal Prices (Constrained)--the average of NW1 (Captain Jack/Malin--COB) and NW3 (NOB) for HLH and LLH

NYMEX Mid C = the New York Mercantile Exchange Futures
Electricity Closing Price at Mid-C for the applicable
month

California PX prices will be adjusted for basis difference between COB/NOB and
the Mid-C using the IS/PTP Rates contained in BPA's 1996 Transmission Rate
Schedules.