2002 Final Power Rate Proposal

Administrator's Record of Decision

Appendix 1: 2002 Wholesale Power Rate Schedules

WP-02-A-02
May 2000

2002 WHOLESALE POWER RATES
TABLE OF CONTENTS

COMMONLY USED ACRONYMS

AANR	Actual Accumulated Net Revenues
AC	Alternating Current
ACME	Accelerated California Market Estimator
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APA	Administrative Procedures Act
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act

CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DOE	Department of Energy
Draft Rod	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EFP	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour

HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IPC	Idaho Power Company
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IJC	International Joint Commission
IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
IS	Southern Intertie
ISC	Investment Service Coverage
ISO	Independent System Operator
JOA	Joint Operating Agency
Joint DSI	Alcoa, Vanalco, and DSI
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
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MVA	Megavar
MVAR	Megavoltamperes
MW	Megawatt (1 million watts)

MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEEA	Northwest Energy Efficiency Alliance
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Integration Transmission
NTP	Network Integration Transmission (rate) for 1981 Power Sale Contracts
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk

PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RESEXRAM	Residential Exchange Rate Analysis Model
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
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
SCRA	Supplemental Contingency Reserve Adjustment
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act

TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration
WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

2002 WHOLESALE POWER RATE SCHEDULES

INDEX
2002 POWER RATE SCHEDULES

SCHEDULE PF-02
PRIORITY FIRM POWER

SECTION I. AVAILABILITY

This schedule is available for the contract purchase of Firm Power to be used within the Pacific Northwest (PNW). 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 investor-owned utilities (IOU) 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.

For ease of reference BPA uses the term PF rate, and PF Preference rate interchangeably. For the PF Exchange rate, BPA clarifies which rate it is discussing by using either PF Exchange Program rate or PF Exchange Subscription rate.

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

Applicable Months	*Rate*
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/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

Applicable Months	*HLH Rate*	*LLH Rate*
January	19.52 mills/kWh	13.54 mills/kWh
February	17.98 mills/kWh	12.54 mills/kWh
March	16.23 mills/kWh	10.82 mills/kWh
April	12.58 mills/kWh	8.22 mills/kWh
May	12.53 mills/kWh	6.65 mills/kWh
June	15.85 mills/kWh	8.20 mills/kWh
July	21.03 mills/kWh	14.09 mills/kWh
August	31.42 mills/kWh	17.33 mills/kWh
September	22.34 mills/kWh	18.19 mills/kWh
October	15.67 mills/kWh	11.16 mills/kWh
November	21.40 mills/kWh	17.11 mills/kWh
December	22.05 mills/kWh	16.77 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

Applicable Months	*HLH Rate*	*LLH Rate*
January	21.02 mills/kWh	15.04 mills/kWh
February	19.48 mills/kWh	14.04 mills/kWh
March	17.73 mills/kWh	12.32 mills/kWh
April	14.08 mills/kWh	9.72 mills/kWh
May	14.03 mills/kWh	8.15 mills/kWh
June	17.35 mills/kWh	9.70 mills/kWh
July	22.53 mills/kWh	15.59 mills/kWh
August	32.92 mills/kWh	18.83 mills/kWh
September	23.84 mills/kWh	19.69 mills/kWh
October	17.17 mills/kWh	12.66 mills/kWh
November	22.90 mills/kWh	18.61 mills/kWh
December	23.55 mills/kWh	18.27 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

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 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

1. Applicability

This rate is available to customers purchasing the Slice Product for the first five years of their Slice contract. This rate will remain constant during the five years of the rate period.

2. Rate

The monthly rate for the Slice Product is $1,419,430 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

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/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

Applicable Months	***Energy Rate***
January	29.22 mills/kWh
February	27.18 mills/kWh
March	24.53 mills/kWh
April	19.47 mills/kWh
May	18.30 mills/kWh
June	22.84 mills/kWh
July	31.34 mills/kWh
August	44.27 mills/kWh
September	35.08 mills/kWh
October	24.18 mills/kWh
November	33.45 mills/kWh
December	33.95 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

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 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. PF Exchange Program Power
2. PF 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 (GSP)
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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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 Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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 Charges	II.I.
Flexible PF Rate Option	II.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.M.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

G. SLICE PRODUCT

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

1. Slice Product Charge

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

2. Adjustments, Charges, and Special Rate Provisions

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

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewables Discount	II.A.
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Low Density Discount	II.Q.
Slice True-Up Adjustment	II.S.
Unauthorized Increase Charge	II.W.

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 Network Transmission (NT) rate schedule or its successor.

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

c. Adjustments, Charges, and Special Rate Provisions

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation Surcharge	II.B.
Cost Contributions	II.E.
Cost Recovery Adjustment Clause	II.F.
Dividend Distribution Clause	II.H.
Low Density Discount	II.Q.

2. Priority Firm Exchange Subscription Power

This PF Exchange Subscription rate applies to sales under section 5(c) of the Northwest Power Act to IOUs 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

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.N.
Unauthorized Increase Charge	II.W.

SECTION V. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule, except for the exchange product listed under Section IV.H.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 (IOU) under net requirements 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 "Federal Columbia River Benefits Supplied By BPA" 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

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/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

Applicable Months	*HLH Rate*	*LLH Rate*
January	20.12 mills/kWh	14.14 mills/kWh
February	18.58 mills/kWh	13.14 mills/kWh
March	16.83 mills/kWh	11.42 mills/kWh
April	13.18 mills/kWh	8.82 mills/kWh
May	13.13 mills/kWh	7.25 mills/kWh
June	16.45 mills/kWh	8.80 mills/kWh
July	21.63 mills/kWh	14.69 mills/kWh
August	32.02 mills/kWh	17.93 mills/kWh
September	22.94 mills/kWh	18.79 mills/kWh
October	16.27 mills/kWh	11.76 mills/kWh
November	22.00 mills/kWh	17.71 mills/kWh
December	22.65 mills/kWh	17.37 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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.N.
Unauthorized Increase Charge	II.W.

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

Rates in this schedule 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

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43/kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/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

Applicable Months	*HLH Rate*	*LLH Rate*
January	40.87 mills/kWh	28.97 mills/kWh
February	37.79 mills/kWh	26.97 mills/kWh
March	34.32 mills/kWh	23.55 mills/kWh
April	27.06 mills/kWh	18.37 mills/kWh
May	26.95 mills/kWh	15.25 mills/kWh
June	33.56 mills/kWh	18.33 mills/kWh
July	43.86 mills/kWh	30.06 mills/kWh
August	64.54 mills/kWh	36.50 mills/kWh
September	46.48 mills/kWh	38.22 mills/kWh
October	33.21 mills/kWh	24.23 mills/kWh
November	44.60 mills/kWh	36.07 mills/kWh
December	45.90 mills/kWh	35.39 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

Applicable Months	*HLH Rate*	*LLH Rate*
January	42.37 mills/kWh	30.47 mills/kWh
February	39.29 mills/kWh	28.47 mills/kWh
March	35.82 mills/kWh	25.05 mills/kWh
April	28.56 mills/kWh	19.87 mills/kWh
May	28.45 mills/kWh	16.75 mills/kWh
June	35.06 mills/kWh	19.83 mills/kWh
July	45.36 mills/kWh	31.56 mills/kWh
August	66.04 mills/kWh	38.00 mills/kWh
September	47.98 mills/kWh	39.72 mills/kWh
October	34.71 mills/kWh	25.73 mills/kWh
November	46.10 mills/kWh	37.57 mills/kWh
December	47.40 mills/kWh	36.89 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

Applicable Months	*HLH Rate*	*LLH Rate*
January	41.47 mills/kWh	29.57 mills/kWh
February	38.39 mills/kWh	27.57 mills/kWh
March	34.92 mills/kWh	24.15 mills/kWh
April	27.66 mills/kWh	18.97 mills/kWh
May	27.55 mills/kWh	15.85 mills/kWh
June	34.16 mills/kWh	18.93 mills/kWh
July	44.46 mills/kWh	30.66 mills/kWh
August	65.14 mills/kWh	37.10 mills/kWh
September	47.08 mills/kWh	38.82 mills/kWh
October	33.81 mills/kWh	24.83 mills/kWh
November	45.20 mills/kWh	36.67 mills/kWh
December	46.50 mills/kWh	35.99 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 NLSL'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), unless BPA and the Purchaser agree to bill based on a contract amount of energy.

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

(2) the NLSL'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 NLSL's Measured Energy for the billing period as specified in the contract
multiplied by
the Load Variance Rate from Section II.C.

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

2. Adjustments, Charges, and Special Rate Provisions

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

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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 GSP 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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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 Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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 Charges	II.I.
Flexible NR Rate Option	II.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

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:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
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.L.
Green Energy Premium	II.N.
Low Density Discount	II.Q.
Rate Melding	II.R.
Stepped-Up Multiyear Block (SUMY)	II.T.
Targeted Adjustment Charge	II.V.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

All customers will need to obtain transmission for delivery of products listed under this rate schedule unless BPA's 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 Industrial Firm Power Targeted Adjustment Charge (IPTAC), to BPA's direct service industrial customers (DSI) for Firm Power to be used in their industrial operations. DSIs that purchase power under contracts for which power deliveries begin on October 1, 2001 (2002 Contracts), are eligible to purchase under this rate schedule for 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 Industrial Firm Power (IP) 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.

1.2 Rate Table

Applicable Months	***Rate***
January	$2.16/kW-mo
February	$2.03/kW-mo
March	$1.82/kW-mo
April	$1.45/kW-mo
May	$1.43\kW-mo
June	$1.79/kW-mo
July	$2.31/kW-mo
August	$2.31/kW-mo
September	$2.31/kW-mo
October	$1.76/kW-mo
November	$2.31/kW-mo
December	$2.31/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 IPTACs specified in section 2.2 or 3.2 below.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	21.86 mills/kWh	15.88 mills/kWh
February	20.31 mills/kWh	14.88 mills/kWh
March	18.57 mills/kWh	13.16 mills/kWh
April	14.92 mills/kWh	10.55 mills/kWh
May	14.86 mills/kWh	8.98 mills/kWh
June	18.18 mills/kWh	10.53 mills/kWh
July	23.36 mills/kWh	16.43 mills/kWh
August	33.76 mills/kWh	19.66 mills/kWh
September	24.68 mills/kWh	20.53 mills/kWh
October	18.01 mills/kWh	13.50 mills/kWh
November	23.74 mills/kWh	19.45 mills/kWh
December	24.39 mills/kWh	19.11 mills/kWh

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

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

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

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

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

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

C. LOAD VARIANCE RATE

The Load Variance rate for FY 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 THE IPTAC PRODUCT

Only the firm take-or-pay Block Product is available under this rate schedule. Energy charges for the IPTAC product would apply as specified in Sections II.B.2. and II.B.3.

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

A. 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 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:

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Conservation and Renewable Discount	II.A.
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.K.
Green Energy Premium	II.N.
Industrial Firm Power Targeted Adjustment Charge	II.P.
Rate Melding	II.R.
Supplemental Contingency Reserves Adjustment	II.U.
Unauthorized Increase Charge	II.W.

SECTION IV. TRANSMISSION

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

NF-02
NONFIRM ENERGY 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 25.18 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 30.22 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 25.18 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.

Adjustments, Charges, and Special Rate Provisions	***2002 GRSPs Section***
Cost Contributions	II.E.
Unauthorized Increase Charge	II.W.

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 PBL and the customer negotiate otherwise at time of sale.

BPA'S 2002

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER RATES

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GENERAL RATE SCHEDULE PROVISIONS

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SECTION III: DEFINITIONS

SECTION III: DEFINITIONS (Continued)

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). BPA has requested that FERC make these rates and 2002 GRSPs effective on October 1, 2001. 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 Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 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. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. A late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the applicable "Prime Rate" (reported in the "Money Rates" Section of the Wall Street Journal) plus 4 percent; by 365. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

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

E. Provision for Reassignment of Surplus Transmission Capacity

PBL may reassign transmission capacity that it has reserved for its own use at a price not to exceed the highest of: (1) the original transmission rate paid by PBL; or (2) the applicable transmission provider's maximum stated firm transmission rate on file at the time of the transmission reassignment. Except for the price, the terms and conditions under which the reassignment is made shall be the terms and conditions governing the original grant by the transmission provider. Transmission capacity may only be reassigned to a customer eligible to take service under the transmission provider's open access transmission tariff or other transmission rate schedules.

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 PNW, BPA is offering a C&R Discount to customers purchasing under the Priority Firm Power (PF-02), New Resource Firm Power (NR-02), and Residential Load (RL-02) rate schedules. Purchasers of the Slice product and benefits provided as a cash payment in settlement of the Residential Exchange Program will also be eligible for the C&R Discount.

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 C&R Discount will be a fixed monthly amount based on the customer's forecasted purchases and Residential Exchange Program settlement benefits 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 qualifying conservation and renewable resource projects during the Discount Period. Any customer that has not spent at least as much money on Qualifying Expenditures as the cumulative C&R Discount received from BPA must reimburse the difference to BPA.

Purchasers accepting the monthly C&R Discount agree to abide by the implementation provisions specified in the C&R Discount Implementation Manual.

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 Power Purchases and settlement benefits (in kWh) multiplied by the Unit Discount. (Because the average contract is used, the Unit Discount does not vary by month).

b. **Determination of the "Unit Discount"**

The Unit Discount will equal 0.50 mills/kWh for Subscription Power Purchases and settlement benefits. The Unit Discount for eligible Pre-Subscription contracts will be determined based on individual contract provisions.

c. **Determination of Individual Customer Discounts**

For a participating customer buying power from BPA, the monthly dollar discount will be determined by multiplying the customer's forecasted average monthly Subscription Power Purchases and settlement benefits for each contract year by the Unit Discount.

d. **Determination of Subscription Power Purchases**

1. To determine each customer's average monthly Subscription Power Purchase, BPA will use the customer's Net Requirements purchase, as established in the customer's Subscription contract to calculate the following:

    i. When a customer's contract explicitly calculates Net Requirements purchases for a contract year, the customer's monthly average Subscription Power Purchases are equal to the total annual Net Requirements purchases divided by 12.

    ii. When a customer's contract specifies only the monthly kWh output of the customer's resources, the customer must provide its Account Executive with a monthly load forecast of its Net Requirements purchases. The customer's total annual Net Requirements purchases will then be estimated, for purposes of applying the C&R Discount, by subtracting the customer's forecasted total annual resource output from its forecasted annual Requirements purchases and dividing the result by 12.

2. BPA shall treat benefit amounts provided as cash in settlement of Residential Exchange Program as described in their Subscription settlement contract as Subscription Power Purchases for purposes of this calculation.

e. **Annual Review of Individual Customer Discounts**

At least 30 days prior to the start of each contract year, customers will submit, to their Account Executive, adjustments to the monthly Subscription Power Purchase amounts, referred to in section 2 d. above, as specified in their BPA contract. Subscription Power Purchase increases or decreases of greater than 5 percent, year-to-year, will be reflected in the monthly C&R Discount amounts consistent with section 2 c., above.

f. **Application of the Discount**

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

ii. BPA will provide the C&R Discount even in those months when the C&R Discount amount is larger than the customer's total power bill amount.

3. Qualifying Expenditures

a. Participating customers shall record all individual Qualifying Expenditures by the categories required for the Final Reconciliation Report 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.

b. 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 C&R 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 C&R Discounts received to date and their annual and cumulative Qualifying Expenditures by category. If the report shows that the customer's Qualifying Expenditures are less than or equal to its cumulative C&R 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 C&R 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;

ii. The cumulative Dividend Distribution Clause (DDC) amount dedicated to Qualifying Expenditures that the customer has received from BPA during the Discount Period; and

iii. 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.)

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 C&R Discount."

d. Exemption Language

If states, municipalities, or other governmental bodies in the BPA service territory require, by law or regulation, that a customer, participating in the C&R Discount, 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.

If any utility, participating in the C&R Discount, reports Qualifying Expenditures amounting to 3 percent or more of its retail revenues, then such expenditures 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 Qualifying 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 C&R Discount received from BPA exceed 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 (which is December 1, 2006, for the five-year customers). If the customer's Qualifying Expenditures still do not equal or exceed its cumulative C&R Discount receipts, 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, for the five-year customers) shall be subject to a late payment charge as described in their Subscription contract.

6. Revenue Dividends

If BPA declares a Dividend Distribution 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 and report two dollars of additional investment in eligible activities to receive credit toward one dollar of their Dividend Distribution share (*i.e.,* any C&R dividend will be leveraged on a two for one basis).

3. The Unit Discount for participating customers receiving the Dividend Distribution will be reset to reflect the actual amount of the DDC and their Subscription Power Purchases during the months the Dividend Distribution is in effect.

B. Conservation Surcharge

The Conservation Surcharge, where implemented shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge would apply to PF-02 (including Slice purchasers), RL-02, and NR-02 rate schedules.

C. Cost-Based Indexed IP Rate

The Cost-Based Indexed IP Rate shall be offered to any DSI Purchaser to serve its aluminum smelter operations, and at BPA's sole discretion to any other DSI Purchaser, where the DSI Purchaser makes a contractual commitment to purchase power for all five years of the rate period from BPA under the Cost-Based Indexed IP Rate.

For DSI aluminum companies, the Cost-Based Indexed IP Rate will provide the monthly price for power by applying a monthly average index price for aluminum, to an established Rate Curve (sliding function) explained below.

The Rate Curve sets the key parameters for determining the monthly power price. This Rate Curve will have: (1) an aluminum midpoint value established at the time the power contract is finalized; (2) an upper pivot point 6 cents/lb., above the aluminum midpoint value which sets an aluminum ceiling price above which the power price will not increase further as aluminum prices rise; and (3) a lower pivot point 6 cents/lb., below the aluminum midpoint value which sets an aluminum floor price below which the power price will not decrease further as aluminum prices fall.

The appropriate IPTAC as specified in Sections II.B.2. and II.B.3. of the IP-02 will establish a power price midpoint of $23.50/MWh or $25.00/MWh for each DSI Purchaser. Depending on the applicable IPTAC rate, a lower rate limit will be set at $19.00/MWh or $20.50/MWh, and an upper rate limit will be set at $28.50/MWh or $30.00/MWh.

A Cost-Based Indexed IP Rate will also be available, at BPA's sole discretion, to non-aluminum DSIs. Any Indexed Rate offered to non-aluminum DSI customers will be designed to recover the equivalent of $23.50/MWh over the rate period, and must be based on a commodity that is a direct product of the purchaser. This commodity must be tied to a commercially recognized price index that is: (1) relied upon by multiple producers; (2) used commercially to set settlement terms between producers and consumers; (3) used for establishing longer term prices and for hedging.

1. **Calculation of the Average Annual IPTAC (A) and (B)**

   The average annual IPTAC rates are calculated from annual billing determinants specified in the IP-02 Rate Schedule. The annual average of all billing determinant, including the monthly IP demand charges, the monthly LLH and HLH IP energy rates, plus the appropriate charge specified in either Sections II.B.2. or II.B.3. of the IP-02 Rate Schedule, are used to calculate the power rate midpoints.

   The power price at the midpoint value of IPTAC (A) is 23.5 mills/kWh.
   The power price at the midpoint value of IPTAC (B) is 25.0 mills/kWh.

2. **Establishing the Rate Curve**

   The rate curve has three main features: (1) a power price midpoint value of $23.50/MWh or $25.0/MWh; (2) a lower pivot point of $19.00/MWh or $20.50/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to fall; and (3) an upper pivot price of $28.50/MWh or $30.00/MWh, the point on the rate curve where the price of energy remains unchanged as the price of aluminum continues to rise. The following criteria will be used in establishing this rate curve.

   a. The aluminum midpoint value of the rate curve shall be established at the average of aluminum forward price swap quotes received by BPA on the day of pricing, plus an appropriate risk premium of up to 2 cents. The aluminum midpoint value will not be set above 74 cents/lb. for aluminum, or below 66 cents/lb. for aluminum.

   b. The lower pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents lb., less than the aluminum midpoint value; the lower pivot point will intersect with the lower rate limit. The rate of

change from the aluminum midpoint value to the lower pivot point is -$0.75/MWh for each cent/lb., aluminum.

c. The upper pivot point shall be established on the rate curve at the point the price of aluminum is 6 cents/lb., greater than the aluminum midpoint value; the upper pivot point will intersect with the upper rate limit. The rate of change from the aluminum midpoint value to the upper pivot point is $0.833/MWh for each cent/lb., aluminum.

Power prices assessed under this rate curve shall be rounded to the nearest $1/10^{th}$ or $0.1/MWh.

3. **Monthly Rate Determination**

The power rate of a DSI Purchaser who has selected the Cost-Based Indexed IP Rate option shall be determined each month for billing purposes. For DSI aluminum companies the monthly power rate is determined by applying the average aluminum price to the rate curve. The following criteria shall be used to calculate the average aluminum price for the billing month.

a. The arithmetic mean of the previous month's London Metal Exchange Aluminum H.G. three month (LME – 3-month) futures contract (US $) shall establish the average aluminum price for the billing month.

b. Such average aluminum price shall be applied to the purchaser's rate curve to determine the power rate for the billing month.

c. Monthly power rates under the Cost-Based Indexed IP Rate shall be a single flat energy rate for each month. There will not be a separate charge for demand and energy.

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 (COB) (location) and the Dow Jones cash or the New York Mercantile Exchange (NYMEX) 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 heavy load hour (HLH) and a light load hour (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: (1) the average of the closing price for the last 15 days of trading if using a futures market such as NYMEX; or (2) the monthly volume weighted average of all posted daily prices if using a cash market such as Dow Jones. The MIMA will be calculated as follows:

Index	=	BPA's current forecast or forward transaction price of the market index referenced
PF	=	Monthly PF demand and HLH and LLH energy rates.
Cost of Insurance	=	The premium on a physical or financial instrument used to mitigate the risk.
MIMA	=	Index price minus PF (forward price or forecast) + Cost of Insurance.

Note: when index price (at contract origination) is above PF, the resulting adjustment before insurance will be the application of a discount. When the index price (at contract origination) is below PF, the resulting adjustment before insurance will be the application of a premium. All adjustments are fixed for the duration of the rate period.

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 19.38 mills/kWh.

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

Table A

Rate Schedule	***Resource Cost Contribution***		
	Federal Base System	**Exchange**	**New Resources**
PF	100%	0%	0%
IP	51.31%	44.99%	3.70%
NR	51.31%	44.99%	3.70%

F. Cost Recovery Adjustment Clause (CRAC)

The CRAC is a temporary, upward adjustment to posted power rates for Subscription sales 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: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), including the financial portion of any Residential Exchange Settlement under this rate schedule, New Resource Firm Power (NR-02), and Subscription purchase under Firm Power Products and Services (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 at the end of any Fiscal Year 2001 through 2004 falls below the CRAC Threshold applicable to that fiscal year, the CRAC triggers, a rate increase 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 actual generation function net revenues, as accumulated since 1999, 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 annual amount planned to be recovered through the CRAC. Rate increases under the CRAC take effect on April 1 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 effective the following April 1. 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	-250	150
2004	-250	150
2005	-250	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**

i. Each quarter, BPA shall post on its electronic information access (World Wide Web) site preliminary, unaudited year-to-date aggregate financial results for generation, including accumulated net revenues.

ii. By no later than August 31 of each year, BPA shall post on its website 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 website the unaudited AANR.

b. **Actions to Mitigate Need for a CRAC**

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

c. **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 the extent to which BPA intends to adjust rates 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 GSP by the customer's Total Retail Load on their system peak. The minimum Demand

Adjuster is 0.6 six tenths. The Demand Adjuster is used with the demand billing factor for the Actual Partial Service Products, and with the demand billing factor for the Block with Factoring.

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: PF Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02) including the financial portion of any Residential Exchange Settlement under this rate schedule, New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). The DDC does not apply to Pre-Subscription rates or Slice purchases.

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 Conservation and Renewables Discount (C&R Discount), or to other customers and stakeholders.

"Stakeholders" are groups or public purposes 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.

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 1999, 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 $250 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

In January 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 Years 2002-2005, remain in effect 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 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* C&R Discount GRSPs, 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 website 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 website 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 kWh, than the underlying load would have used.

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

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 Independent System Operator (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 Power Exchange (CalPX) (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 Dow Jones (DJ) Mid-Columbia (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.

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

In the event that the index for 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 CalPX (NW1 or NW3), at a hub at which Northwest parties can trade.

J. Five-Year Flat Block Price Forecast

The Five-Year Flat Block Price Forecast is BPA's price estimate of the market price for five-year block purchases for the 2002-2006 period. This forecast is used in calculating the cash component of the proposed settlement of the Residential Exchange Program with regional IOUs as described in BPA's Power Subscription Strategy. The Five-Year Flat Block Price Forecast is $28.1 per megawatthour (MWh).

K. 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 NPV 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.

L. 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 NPV 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 Stepped-Up Multiyear Block (SUMY), if appropriate) charges specified in the PF rate schedule Section II, unless such power would be charged as an Unauthorized Increase.

M. 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 NPV 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.

N. Green Energy Premium

1. Overview of the Premium

The Green Energy Premium (GEP) is a premium ranging from zero to $40/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 MWh 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 customer.

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 GEP will be determined as part of the product selection process and will be completed as part of the power sales contract negotiation. The charge will not exceed $40 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 GEP will recover the average unit cost of the EPP resource(s) minus the applicable average PF-02, RL-02, NR-02, and IP-02 energy charge over the term of the purchase.

b. **Determination of Individual Customer GEP**

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

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

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

c. **Application of the GEP**

The GEP will be applied after BPA has determined all other charges and credits except the C&R 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:

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

O. 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 Nonfirm Energy (NF) Standard rate or Market Expansion rate.

P. Industrial Firm Power Targeted Adjustment Charge (IPTAC)

1. Availability

The 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 average megawatt (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. 1,210 aMW will be sold at $23.50 per MWh, and 230 aMW sold at $25 per MWh.

Q. Low Density Discount (LDD)

1. Application and Definitions

For eligible Purchasers as defined in section 2 below, a discount shall be applied each billing month to BPA's charges for the following components of the PF Preference rate, the PF Exchange Program rate, and the NR-02 rate: (1) Demand; (2) HLH purchases; (3) LLH purchases; and (4) Load Variance. The Low Density Discount (LDD) shall not be applied to Unauthorized Increase Charges, Excess Factoring Charges, transmission charges or any other charges. The discount shall be revised annually based on data supplied by June 30 of each Calendar Year (CY) for the previous CY and shall become effective on the upcoming October 1.

a. **The 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 within the distribution system, in any one month during the CY, by the end of CY number of pole miles of distribution.

Consumer means every billed consumer regardless of usage. Separately billed services for water heating and security lights are not counted as 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 (kV) or less, to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

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

In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the PNW. For 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

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

4. LDD Phase-Out Adjustment

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

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

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

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

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

5. Additional Adjustment for Very Low Densities

If a Purchaser's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the discount pursuant to sections 3 and 4 above, an additional one-half percent shall be added to the Purchaser's discount, but the total discount

shall not exceed 7 percent. In subsequent years, the one-half percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

6. Retail Access Exclusion

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

7. Application of the LDD to Slice

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

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

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

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

R. Rate Melding

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

S. Slice True-Up Adjustment

Each year, when the audited actual Slice Revenue Requirement for the previous fiscal year is available, BPA will calculate the final true-up for the previous fiscal 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 Power rate case. This true-up will be the True-Up Adjustment Charge and will be applied to the customer's bills. See the Slice Product Costing and True-Up Table (Table D). Inventory Solution costs will be trued-up in a slightly different manner, using the formula in Table E.

Table D

			SLICE PRODUCT COSTING AND TRUE-UP TABLE					
			A	B	C	D	E	F
1	PBL Costs ($000)	2002 2006	2002	2003	2004	2005	2006	TOTAL
2	GENERATION COSTS	Audited	Projected →					
3	Federal Base System	Actuals						
4	Hydro							
5	Upstream benefits		$ 1,990	$ 2,050	$ 2,111	$ 2,174	$ 2,240	$ 10,565
6	Corps of Engineers O&M		$ 108,000	$ 112,000	$ 112,000	$ 112,000	$ 112,000	$ 556,000
7	Corps Depreciation		$ 73,329	$ 75,497	$ 78,292	$ 81,258	$ 83,620	$ 391,996
8	U.S. Fish & Wildlife O&M		$ 15,800	$ 16,197	$ 16,995	$ 17,892	$ 18,789	$ 85,273
9	Bureau of Reclamation O&M		$ 47,000	$ 48,300	$ 48,300	$ 48,300	$ 48,300	$ 240,200
10	Bureau Depreciation		$ 19,470	$ 20,043	$ 20,535	$ 21,009	$ 21,516	$ 102,573
11	Colville Settlement		$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 16,000	$ 80,000
12	Packwood Dam		$ 2,343	$ 2,577	$ 2,835	$ 3,118	$ 3,430	$ 14,301
13	Net Interest Expense		$ 157,914	$ 158,579	$ 166,657	$ 176,226	$ 177,170	$ 836,546
14	**Subtotal**		**$ 441,846**	**$ 451,243**	**$ 463,724**	**$ 477,977**	**$ 483,065**	**$ 2,317,455**
15	Fish and Wildlife							
16	Expense		$ 131,700	$ 138,000	$ 140,100	$ 142,900	$ 144,400	$ 697,100
17	Amortization		$ 19,772	$ 21,842	$ 23,737	$ 25,394	$ 26,407	$ 117,152
18	Net Interest Expense		$ 6,540	$ 6,759	$ 7,181	$ 7,259	$ 7,166	$ 34,905
19	**Subtotal**		**$ 158,012**	**$ 166,601**	**$ 171,018**	**$ 175,553**	**$ 177,973**	**$ 849,157**
20	Trojan							
21	Decommissioning		$ 9,600	$ 4,200	$ 2,600	$ 2,600	$ 2,600	$ 21,600
22	Debt Service		$ 9,947	$ 9,954	$ 9,964	$ 9,989	$ 10,009	$ 49,863
23	**Subtotal**		**$ 19,547**	**$ 14,154**	**$ 12,564**	**$ 12,589**	**$ 12,609**	**$ 71,463**
24	WNP #1							
25	O&M		$ 400	$ 384	$ 384	$ 384	$ 384	$ 1,936
26	Debt Service		$ 177,704	$ 167,856	$ 174,623	$ 167,910	$ 179,992	$ 868,085
27	**Subtotal**		**$ 178,104**	**$ 168,240**	**$ 175,007**	**$ 168,294**	**$ 180,376**	**$ 870,021**
28	WNP #2							
29	O&M/Capital Requirements		$ 154,094	$ 163,824	$ 170,724	$ 173,824	$ 179,824	$ 842,290
30	Debt Service		$ 197,442	$ 244,980	$ 233,624	$ 187,825	$ 211,976	$ 1,075,847
31	**Subtotal**		**$ 351,536**	**$ 408,804**	**$ 404,348**	**$ 361,649**	**$ 391,800**	**$ 1,918,137**
32	WNP #3							
33	Debt Service		$ 153,720	$ 152,993	$ 149,232	$ 149,490	$ 147,836	$ 753,261
34	**Total**		**$ 1,302,364**	**$ 1,362,035**	**$ 1,375,894**	**$ 1,345,542**	**$ 1,393,659**	**$ 6,779,494**
35								
36	New Resources							
37	Idaho Falls		$ 3,740	$ 3,737	$ 3,744	$ 3,754	$ 3,754	$ 18,729
38	Cowlitz		$ 14,914	$ 14,987	$ 15,051	$ 15,123	$ 15,196	$ 75,271
39	Firm Purchased Power		$ 17,723	$ 17,953	$ 18,187	$ 18,436	$ 18,681	$ 90,978
40	Competitive Acquisitions		$ 12,158	$ 12,340	$ 12,526	$ 12,713	$ 12,904	$ 62,642
41	Columbia Hills (CARES)		$ 4,323	$ 4,369	$ 4,397	$ 4,446	$ 4,490	$ 22,015
42	Wheeling Power Purchase		$ 1,242	$ 1,253	$ 1,264	$ 1,275	$ 1,287	$ 6,321
43	Other Acquisitions		$ -	$ -	$ -	$ -	$ -	$ -
44	**Total**		**$ 36,377**	**$ 36,677**	**$ 36,982**	**$ 37,312**	**$ 37,631**	**$ 184,978**
45								
46	Legacy Conservation							
47	Conservation expense		$ 18,201	$ 16,613	$ 16,913	$ 17,313	$ 17,613	$ 86,651
48	Generation Billing Credits		$ 7,934	$ 7,898	$ 7,866	$ 7,834	$ 7,785	$ 39,317
49	Conservation Financing		$ 5,578	$ 5,577	$ 5,577	$ 5,577	$ 5,577	$ 27,886
50	Conservation Amortization		$ 59,337	$ 55,586	$ 47,125	$ 43,179	$ 37,650	$ 242,877
51	Conservation Interest		$ 38,022	$ 39,345	$ 35,237	$ 34,779	$ 32,001	$ 180,184
52	**Subtotal**		**$ 129,072**	**$ 125,019**	**$ 112,718**	**$ 108,681**	**$ 100,626**	**$ 576,915**
53	Energy Services Business		$ 11,883	$ 11,890	$ 11,601	$ 11,475	$ 11,444	$ 57,873
54	Other Generation Costs							
55	BPA Programs							
56	CSRS Pension Expense		$ 27,600	$ 17,550	$ 15,450	$ 13,350	$ 11,500	$ 85,450
57	Power Marketing		$ 16,000	$ 15,700	$ 8,800	$ 6,800	$ 5,000	$ 52,300
58	Power Scheduling		$ 20,900	$ 12,800	$ 12,100	$ 12,800	$ 12,700	$ 71,300
59	Inventory Solution Hedging Activities		$ -	$ -	$ -	$ -	$ -	$ -
60	Generation Oversight		$ 2,964	$ 2,950	$ 3,050	$ 3,050	$ 3,150	$ 15,163
61	Administrative & Support Services		$ 17,350	$ 16,650	$ 16,650	$ 16,650	$ 16,650	$ 83,950
62	Power Planning Council		$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 5,100	$ 25,500
63	Miscellaneous Depreciation		$ 4,296	$ 4,093	$ 4,393	$ 3,411	$ 2,973	$ 19,756
64	Geothermal Demonstration		$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 15,768	$ 78,840
65	Renewables		$ 3,091	$ 2,870	$ 2,683	$ 2,551	$ 2,459	$ 13,654
66	Contingency Resources		$ 391	$ 369	$ 317	$ 395	$ 342	$ 1,814
67	Net Interest Expense		$ 406	$ 359	$ 325	$ 312	$ 308	$ 1,710
68	Between Business Line Expense		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 20,000
69	Other							
70	WNP #3 Plant		$ 3,086	$ 3,169	$ 3,169	$ 3,169	$ 3,169	$ 15,762
71	**Total Other Generation Costs**		**$ 120,952**	**$ 101,978**	**$ 91,795**	**$ 87,256**	**$ 83,218**	**$ 485,199**
72	**Minimum Required Net Revenues**		$ -	$ -	$ -	$ -	$ -	$ -
73	**COSA Table Subtotal**		**$ 1,601,227**	**$ 1,637,398**	**$ 1,628,989**	**$ 1,590,266**	**$ 1,626,578**	**$ 8,084,458**

Table D (Continued)

	PBL Costs ($000)	2002-2006	A 2002	B 2003	C 2004	D 2005	E 2006	F TOTAL
		Audited	Projected →					
74		Actuals						
75	Net Residential Exchange Costs		$ -	$ -	$ -	$ -	$ -	$ -
76	Subscription Settlement Costs (900 aMW's in §)		$ 69,725	$ 69,725	$ 69,725	$ 69,725	$ 69,725	$ 348,626
77								
78	Slice Initial Implementation Expenses		$ -	Not applicable	Not applicable	Not applicable	Not applicable	$ -
79	Slice Implementation Expenses		$ -	$ -	$ -	$ -	$ -	$ -
80								
81	CEA Transmission Costs		$ 13,514	$ 17,105	$ 26,685	$ 26,685	$ 26,685	$ 110,675
82	Ancillary and Reserve Service Costs		$ 10,000	$ 10,000	$ 8,000	$ 8,000	$ 8,000	$ 44,000
83	PBL PF Trans. Pass-Through Costs		$ -	$ -	$ -	$ -	$ -	$ -
84	PNCA & NTS Transmission Costs		$ 1,815	$ 1,815	$ 1,815	$ 1,815	$ 1,815	$ 9,075
85	General Transfer Agreement Costs		$ 47,200	$ 47,200	$ 47,200	$ 47,200	$ 47,200	$ 236,000
86								
87	**REVENUE REQUIREMENT CHECK**		**$ 1,743,482**	**$ 1,783,243**	**$ 1,782,414**	**$ 1,743,692**	**$ 1,780,003**	0 **$ 8,832,833**
88								
89	PF Conservation and Renewables Credit Costs							$ 95,104
90	IP Conservation and Renewables Credit Costs							$ 31,536
91	RL Conservation and Renewables Credit Costs							$ 21,900
92	LDD		$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 70,000
93	S & I Rate Mitigation Costs		$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 4,000	$ 20,000
94	**Non-COSA Table Subtotal**							$ 238,540
95								
96	**Total PBL Revenue Requirement**							**$ 9,071,373**
97								
98	**Revenue Credits ($000)**							
99	Ancillary and Reserve Service Revs.		$ 80,380	$ 80,293	$ 81,127	$ 81,098	$ 81,025	$ 403,924
100	PBL PF Trans. Pass-Through Revs.		$ -	$ -	$ -	$ -	$ -	$ -
101	Canadian Entitlement Credit		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 5,000
102								
103	COE & USBR Project Revenues		$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 8,100	$ 40,500
104	4(h)(10)(c)		$ 88,147	$ 91,007	$ 90,731	$ 92,873	$ 95,177	$ 457,935
105	Colville Credit		$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 23,000
106	FCCF		$ 51,406	$ 33,261	$ 22,681	$ 16,079	$ 6,899	$ 130,326
107	Sup/Ent Cap; Irr. Pump		$ 938	$ 707	$ 471	$ 471	$ 471	$ 3,059
108	Energy Efficiency Revenues		$ 13,046	$ 13,345	$ 13,345	$ 13,345	$ 13,345	$ 66,426
109	Property Trnfrs & Misc.		$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 3,416	$ 17,080
110								
111	**Total Revenue Credits**							**$ 1,147,249**
112								
113	**Power Revenues Needed**							**$ 7,924,124**
114								
115	Firm System Augmentation (1282 aMWs on average)		$ 322,218	$ 336,766	$ 289,159	$ 323,744	$ 306,070	$ 1,577,958
116	DSI Augmentation (450 aMWs)		$ 113,888	$ 113,888	$ 113,888	$ 113,888	$ 113,888	$ 569,442
117	Conservation Augmentation (20,40,60,80,100 aMW)		$ 5,415	$ 10,831	$ 16,246	$ 21,662	$ 27,077	$ 81,231
118	**Total Cost of Inventory Solution**		**$ 441,522**	**$ 461,485**	**$ 419,294**	**$ 459,294**	**$ 447,036**	**$ 2,228,632**
120								
121	Revenue 1282 aMWs flat, 450 aMWs to DSIs		$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)	$ (327,235)	$ (1,636,175)
122	**Net Cost of Inventory Solution**		**$ 114,287**	**$ 134,250**	**$ 92,059**	**$ 132,060**	**$ 119,801**	**$ 592,457**
123								
124		($000)						
125	**Annual Slice Revenue Requirement**	**$ 1,703,316**						
126	**Monthly Slice Revenue Requirement**	**$ 141,943**				**Five Year Total**		**$ 8,516,581**
127	**One Percent of Monthly Requirement**	**$ 1,419.43**						
128								

T. 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 TAC.

The cost for the SUMY Block service is the difference between PF-02 rates and the AURORA On and Offpeak 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.
October 2002 HLH Block minus October 2001 HLH Block = HLH MWh of SUMY Block for October 2002

Step 2: Determine LLH MWh of SUMY Block.
October 2002 LLH Block minus October 2001 LLH Block = LLH MWh of SUMY Block for October 2002

Step 3: Determine Cost of HLH SUMY Block service.
HLH MWh of SUMY Block * (Aurora October 2002 On-Peak Market Price minus October 2002 PF HLH energy and demand rate) = Total Cost of October 2002 HLH SUMY Block service.

Step 4: Determine Cost of LLH SUMY Block service.
LLH MWh of SUMY Block * (Aurora October 2002 Off-Peak Market Price minus October 2002 PF LLH energy rate) = 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.

U. 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 $5.63/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 North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and Northwest Power Pool (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; and

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

In addition to these required characteristics, the issues identified below will help define when 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; and

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

V. Targeted Adjustment Charge (TAC)

1. Availability

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

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

If a public agency customer that requests requirements service from BPA is annexing or otherwise taking on the obligation of load from another public agency customer and the request to annex or take on load obligation and the reduction in obligation are equal amounts such that BPA's total load obligation does not increase, BPA may exempt the newly acquired load from the TAC and apply 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 by assignment through BPA the right to the IOUs power and/or financial benefits applicable to the annexed load. BPA will deliver an amount of firm power to the annexing public agency customer at the PF-02 rate equal to the amount of benefit (power and/or financial) assigned by the IOU to BPA. Power provided by BPA to the public agency customer to meet the remaining annexed load not covered by the benefits assigned from the IOU will be subject to the TAC.

The TAC will apply for the duration of the Customer's contract or until 2006, whichever occurs first. For five-year contracts that guarantee rates for multiple periods (for example, contracts that have both three- 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 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:

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

where:

TAC Amt	=	The amount of load subject to the TAC, determined monthly.
Rate $	=	The monthly PF (or NR) energy rate shown in the applicable rate schedule.
Inventory Amt	=	Amount of energy in inventory available to serve this load based on 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 CalPX.
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).

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.

W. 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 Nevada-Oregon Border (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).

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

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 CalPX, NW1 (COB);

(2) the highest price experienced for the month at the CalPX, 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)

CSP is the largest measured HLH Total Retail Load 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 (IP)

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

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 (NR)

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

a. for any NLSL; and

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

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

NR is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. NR is power where BPA agrees to provide operating reserves in accordance with the standards established by the NERC, WSCC, and the NWPP.

12. Nonfirm Energy (NF)

Nonfirm Energy Power (NF) 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. NF is sold primarily under the NF rate schedule, NF-02. NF also may be supplied under the NF-02 rate schedule to the WSPP subject to terms and conditions agreed upon by the members participating

in the WSPP and in accordance with BPA policy for such arrangements. NF that has been purchased under a guarantee provision in the NF 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 NF available to purchasers both inside and outside the United States.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange under section 5(c) of the Northwest Power Act may purchase PF pursuant to their Residential Exchange contracts with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

PF is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeure* events. PF is power 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 Automatic Generation Control (AGC) signals without human intervention. Regulation and frequency response is required to provide AGC response to load and generation fluctuations in an effective manner and to maintain desired compliance with NERC AGC Control Performance.

15. Residential Exchange Program Power

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

16. Slice Product

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

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 (CalPX)

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 CalPX 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 powerflow 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)

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

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 (GSP)

The GSP 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

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. 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.

31. NP15

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

32. NW1 (COB)

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

33. NW3 (NOB)

CalPX and California ISO designation for delivery at NOB.

34. Partial Service Customer

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

35. Point of Delivery (POD)

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

36. 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.

37. Point of Interconnection (POI)

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

38. Points of Metering (POM)

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

39. 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.

40. 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.

41. Receiving Party

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

42. Retail Access

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

43. 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.

44. 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.

45. Slice Revenue Requirement

The Slice Revenue Requirement is comprised of the items in BPA's PBL revenue requirement used to calculate the Slice product charge, as identified in the PBL's 2002 and 2007 Power rate cases. *See* Table D.

46. 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.

47. Subscription Contract

See 2002 Contract.

48. 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.

49. Total Retail Load (TRL)

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

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

50. Utility Distribution Company (UDC)

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

TABLE E

Inventory Solution True-Up Adjustment

The Inventory Solution True-Up Adjustment (ISTU) is calculated once during each rate period and is calculated in the following manner:

$ISTU_R = (CL_R - FL_R)/ ISMW_R * NCIS_R/12$

Where:

$ISTU_R$ is the Inventory Solution True-Up Adjustment for the rate period R.

CL_R is the annual average Contracted Loads for the rate period R. Contracted Loads for each five-year rate period shall be the average of five Fiscal Year loads contracted for in annual aMW for the Public Agency customers, DSI customers to be served with FBS resources, IOU customers to be served with FBS resources, and the Preexisting Multiyear Contracts that are known to BPA.

FL_R is the annual average Forecasted Loads for the rate period R. Forecasted Loads for each five-year rate period shall be the average of five forecasted Fiscal Year loads in annual aMW that was included in the applicable Final Power Rate Proposal for the Public Agency loads, DSI loads to be served with FBS resources, IOU loads served with FBS resources, and Preexisting Multiyear Contracts.

(CL_R-FL_R) cannot be a value less than zero.

$ISMW_R$ is the annual average MW associated with the Inventory Solution for the rate period R.

$NCIS_R$ is the annual average net cost of the Inventory Solution for the rate period R.