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

BP-26 Rate Proceeding

Initial Proposal

2026 Power Rate Schedules and General Rate Schedule Provisions (FY 2026-2028)

BP-26-E-BPA-10

November 2024

BONNEVILLE POWER ADMINISTRATION

2026 POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

TABLE OF CONTENTS

APPENDIX

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also “NPCC”)
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service

DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	environmental impact statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources

IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
OATT	Open Access Transmission Tariff

O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	point of receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service

SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool.

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POWER RATE SCHEDULES

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POWER RATE SCHEDULES

INDEX

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SCHEDULE PF-26
PRIORITY FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of the “general requirements” portion of Firm Requirements Power by public bodies, cooperatives, and federal agencies pursuant to Sections 5(b) and 7(b) of the Northwest Power Act. 16 U.S.C. § 839c(b), 16 U.S.C. §§ 839e(b)(1), (b)(4); . Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service.

This schedule is also available for the contract purchase of Residential Exchange Program Power by utilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). Purchases are made pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

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

Effective October 1, 2025, this rate schedule supersedes the PF-24 rate schedule. Sales under the PF-26 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills will be rendered and payments due pursuant to the GRSPs and billing process.

2. Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under Contract High Water Mark (CHWM) contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

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

2.1.1 Customer Charges

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

2.1.1.1 Customer Rates

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

	Customer Charge Rate in Dollars per Percentage Point of Billing Determinant		
	Composite	***Non-Slice***	***Slice***
Customer Rate	2,158,195	(345,685)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer Billing Determinants are specified in the following table:

	Customer Charge Billing Determinant for Each Rate		
	Composite	***Non-Slice***	***Slice***
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percentage.

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

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

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

All customer TOCAs will be posted on the BPA website. A customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

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

Non-Slice TOCA = TOCA minus Slice %, expressed as a percentage.

A customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

2.1.2 Demand Charge

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

2.1.2.1 Demand Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

2.1.2.2 Demand Billing Determinant

The Demand Billing Determinant for each billing month equals:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours (HLH) of the month, in kilowatts

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

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

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

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

If a customer does not supply the Super Peak amount listed in its CHWM Contract, Exhibit A, Section 9, for at least two hours of the Super Peak Period, then the customer does not receive a Super Peak Credit for that month.

The Demand Billing Determinant may be adjusted pursuant to the Demand Rate Billing Determinant Adjustments, GRSP II.D.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or Light Load Hours (LLH)), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping Billing Determinant is positive or negative.

2.1.3.1 Load Shaping Rate

Month	**Rate in mills/kWh**	
	HLH	***LLH***
October	50.63	48.85
November	39.53	41.64
December	47.63	48.79
January	43.56	43.80
February	45.43	49.18
March	29.19	34.54
April	22.33	27.09
May	8.60	12.73
June	15.10	16.08
July	50.98	48.06
August	53.80	50.32
September	60.51	59.06

2.1.3.2 Load Shaping Billing Determinant

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

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

2.1.3.2.1 System Shaped Load

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

$$RT1SC \times TOCA$$

Where:

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

TOCA = The effective TOCA for a Load Following or Block customer, or the effective Non-Slice TOCA for a Slice/Block customer, expressed as a percentage. The TOCA used in this System Shaped Load calculation will reflect a customer's Adjusted TOCA pursuant to GRSP II.G.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load-Shaping Charge Billing Determinant for a JOE, the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System-Shaped Loads of the JOE's individual members will be used.

2.1.4 Risk Adjustments

The Power Cost Recovery Adjustment Clause (Power CRAC) (GRSP II.O), the Power Reserves Distribution Clause (Power RDC) (GRSP II.P), and the Power Financial Reserves Policy Surcharge (Power FRP Surcharge) (GRSP II.Q) are adjustments to certain Tier 1 rates that apply to the following products under the PF-26 rate schedule: Load Following, Block, and the Block portion of Slice/Block. Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in Appendix A.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to Section 4.3 of the Tiered Rate Methodology (TRM), BP-12-A-03, the Tier 2 Load Shaping Charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load of less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates

The Tier 2 Load Shaping Rates will be the rates specified in Section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant

The Tier 2 Load Shaping Billing Determinant for each billing period is incorporated into the Billing Determinant established in Section 2.1.3.2.

2.2.2 Short-Term Charge

The Short-Term Charge is applicable to customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

The Short-Term Rate for BP-26 will default to the fixed-rate listed in 2.2.2.1.1 below, unless a customer elects, through a written request provided to BPA prior to April 1, 2025, the formula rate option listed in 2.2.2.1.2.

2.2.2.1.1 Short-Term Fixed Rate Option (Default)

Fiscal Year	Rate in mills/kWh
2026	70.66
2027	67.40
2028	67.70

2.2.2.1.2 Short-Term Formula Rate Option

The formula-rate option will be based on the Intercontinental Exchange (ICE) Mid-C Day-Ahead Index price, or a comparable replacement if it were to become unavailable, plus the below adder.

Fiscal Year	Rate in mills/kWh
2026	16.95
2027	17.10
2028	17.09

2.2.2.2 Short-Term Billing Determinant

The Short-Term Billing Determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount will be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3 Load Growth Charge

The Load Growth Charge is applicable to customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.3.1 Load Growth Rate

The Load Growth Rate for BP-26 will default to the fixed-rate listed in 2.2.3.1.1 below, unless a customer elects, through a written request provided to BPA prior to April 1, 2025, the formula rate option listed in 2.2.3.1.2.

2.2.3.1.1 Load Growth Fixed Rate Option (Default)

Fiscal Year	Rate in mills/kWh
2026	70.66
2027	67.40
2028	67.70

2.2.3.1.2 Load Growth Formula Rate Option

The formula-rate option will be based on the Intercontinental Exchange (ICE) Mid-C Day-Ahead Index price, or a comparable replacement if it were to become unavailable, plus the below adder.

Fiscal Year	Rate in mills/kWh
2026	16.95
2027	17.10
2028	17.09

2.2.3.2 Load Growth Billing Determinant

The Load Growth Billing Determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount will be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3. Priority Firm Melded Rate

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

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

The PF Melded rate is not available to loads that are considered Unanticipated Loads as defined in Unanticipated Load Service, GRSP II.M.1.

3.1 Energy Charge

3.1.1 Energy Rate

Month	Rate in mills/kWh	
	HLH	***LLH***
October	49.22	47.44
November	38.12	40.23
December	46.22	47.38
January	42.15	42.39
February	44.02	47.77
March	27.78	33.13
April	20.92	25.68
May	7.19	11.32
June	13.69	14.67
July	49.57	46.65
August	52.39	48.91
September	59.10	57.65

The PF Melded energy rates in the table above are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in Appendix A.

3.1.2 Energy Billing Determinant

The Energy Billing Determinant is the total of the hourly loads, as specified in the customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

3.2.2 Demand Billing Determinant

The Demand Billing Determinant is the maximum hourly load, as specified in the customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the PF-26 Rate Schedule, specified in GRSP II.M.2, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

5. Resource Support Services Rates

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

5.1 Diurnal Flattening Service (DFS)

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

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources other than small non-dispatchable resources are subject to the Resource Shaping Charge and Adjustment specified in GRSP II.I.2.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge specified in GRSP II.I.3.

5.4 Grandfathered Generation Management Service (GMS)

Load Following customers dedicating to their Tier 1 Load the entire output of an Existing Resource that received GMS under Subscription are subject to a GMS Reservation Fee specified in GRSP II.I.6.

6. Priority Firm Exchange Rate

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

6.1. Energy Rate

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

Investor-Owned Utilities	**Rates in mills/kWh**		
	Base PF Exchange Rates	***7(b)(3) Surcharge***	***PF Exchange Rates***
Avista	59.60	4.24	63.85
Idaho Power	59.60	2.31	61.92
NorthWestern	59.60	23.22	82.82
PacifiCorp	59.60	36.26	95.86
Portland General	59.60	24.69	84.29
Puget Sound Energy	59.60	14.29	73.90
Consumer-Owned Utilities	***Base Tier 1 PF Exchange Rates***	***7(b)(3) Surcharge***	***PF Exchange Rates***
Snohomish County PUD No 1	58.79	0.26	59.05

6.2 Energy Billing Determinant

The Billing Determinant for the PF Exchange Power charge is the customer's Residential Load specified in GRSP II.S, Table H.

7. Adjustments, Charges, and Special Rate Provisions

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

GRSP II.	**Adjustments, Charges, and Special Rate Provisions**	***Applicable to:*** Firm Requirements: ***Load Following***	***Applicable to:*** Firm Requirements: ***Block only and Block Portion of Slice/Block***	***Applicable to:*** Firm Requirements: ***Slice Portion of Slice/Block***	***Applicable to:*** ***REP***
Calculating Rates (including Discounts and Adjustments)					
A	RHWM Tier 1 System Capability (RT1SC)	X	X		
B	Low Density Discount (LDD)	X	X	X	
C	Irrigation Rate Discount	X	X	X	
D	Demand Rate Billing Determinant Adjustments	X			
E	Load Shaping Charge True-Up Adjustment	X			
F	Tier 2 Rate TCMS Adjustment	X			
G	TOCA Adjustment	X	X	X	
Resource Support Services & Related Services					
I	Resource Support Services and Transmission Scheduling Service	X	X	X	
K	Remarketing	X	X	X	
Transfer Service					
L	Transfer Service Charges	X	X	X	
Other Charges					
M	Unanticipated Load Service	X	X	X	
N	Unauthorized Increase (UAI) Charge	X	X	X	X
Risk Adjustments					
O	Power Cost Recovery Adjustment Clause (Power CRAC)	X	X		
P	Power Reserves Distribution Clause (Power RDC)	X	X		
Q	Power Financial Reserves Policy (Power FRP) Surcharge	X	X		

GRSP II.	Adjustments, Charges, and Special Rate Provisions	*Applicable to:*			
		Firm Requirements			***REP***
		Load Following	***Block only and Block Portion of Slice/Block***	***Slice Portion of Slice/Block***	
Slice True-Up					
R	Slice True-Up Adjustment			X	
Residential Exchange Program					
S	Residential Exchange Program Residential Load				X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment				X
Conservation					
U	Conservation Surcharge	X	X	X	
Payment Options					
W	Flexible Priority Firm Power (PF) Rate Option	X	X	X	
X	Priority Firm Power (PF) Shaping Option	X	X	X	
Informational					
Z	Cost Contributions	X	X	X	X
New Initiatives					
AB	Washington Cap-and-Invest Program Charge	X	X	X	
AC	Resource Adequacy Service	X			

Appendix	Adjustments and Charges	**Applicable to:**		
		Load Following	***Block only and Block Portion of Slice/Block***	***Slice Portion of Slice/Block***
A	Supplemental Information	X	X	X

SCHEDULE NR-26
NEW RESOURCE FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act Section 5(b) requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power also is available to any public body, cooperative, or federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act, including planned NLSLs, as defined in Exhibit D of a customer's CHWM Contract. This schedule also is available for services provided to Load Following customers that are serving NLSLs with non-federal resources.

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

Effective October 1, 2025, this rate schedule supersedes the NR-24 rate schedule. Sales under the NR-26 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills will be rendered and payments due pursuant to the GRSPs and billing process.

2. New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

Month	Rate in mills/kWh	
	HLH	***LLH***
October	134.67	132.89
November	123.57	125.68
December	131.67	132.83
January	127.60	127.84
February	129.47	133.22
March	113.23	118.58
April	106.37	111.13
May	92.64	96.77
June	99.14	100.12
July	135.02	132.10
August	137.84	134.36
September	144.55	143.10

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 7.95 mills/kWh.

2.1.1.2 Risk Adjustments

The NR energy rates in Section 2.1.1 are subject to Risk Adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix A.

2.1.2 Energy Billing Determinant

The Energy Billing Determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

2.2.2 Demand Billing Determinant

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

3. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the NR-26 Rate Schedule, specified in GRSP II.M.3, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

4. Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.J.1, is applicable to Load Following customers that serve NLSLs with non-federal resources.

5. Adjustments, Charges, and Special Rate Provisions

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

GRSP II.	Adjustments, Charges, and Special Rate Provisions
B	Low Density Discount (LDD)
D	Demand Rate Billing Determinant Adjustments
J.1	Energy Shaping Service for NLSLs Charge
M	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Y	Flexible New Resource Firm Power (NR) Rate Option
Z	Cost Contributions
AB	Washington Cap-and-Invest Program Charge

Appendix	Adjustments and Charges
A	Supplemental Information

SCHEDULE IP-26
INDUSTRIAL FIRM POWER RATE

1. Availability

This schedule is available to BPA's direct service industrial (DSI) customers, as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power is available under Northwest Power Act Section 5(d) contracts to DSIs for direct consumption. 16 U.S.C. § 839c(d).

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

Effective October 1, 2025, this rate schedule supersedes the IP-24 rate schedule. Sales under the IP-26 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills will be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-26 rate schedule will be required to provide the Minimum DSI Operating Reserve – Supplemental.

2. Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

Month	Rate in mills/kWh	
	HLH	*LLH*
October	57.46	55.68
November	46.36	48.47
December	54.46	55.62
January	50.39	50.63
February	52.26	56.01
March	36.02	41.37
April	29.16	33.92
May	15.43	19.56
June	21.93	22.91
July	57.81	54.89
August	60.63	57.15
September	67.34	65.89

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 7.95 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.683 mills/kWh Credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Risk Adjustments

The IP energy rates in Section 2.1.1 are subject to Risk Adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix A.

2.1.2 Energy Billing Determinant

The Energy Billing Determinant is the Energy Entitlement that is specified in the customer's contract.

2.2 Demand Charge

2.2.1 Demand Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

2.2.2 Demand Billing Determinant

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

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

Month	Industrial Demand Adjuster (kW)
October	2,046
November	1,646
December	1,160
January	1,019
February	1,115
March	1,598
April	795
May	1,122
June	763
July	793
August	903
September	731

If Port Townsend Paper's Contract Demand (15.75 MW) is reduced in part or in full through a contract action, then the Industrial Demand Adjuster value in the above table will be reduced proportionately and reflected in Appendix A.

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

3. Adjustments, Charges, and Special Rate Provisions

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

GRSP II.	Adjustments, Charges, and Special Rate Provisions
D	Demand Rate Billing Determinant Adjustments
H	DSI Reserves
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Z	Cost Contributions

Appendix	Adjustments and Charges
A	Supplemental Information

SCHEDULE FPS-26
FIRM POWER AND SURPLUS PRODUCTS AND SERVICES RATE

1. Availability

This rate schedule is available for the sale of Firm Power (capacity and/or energy), Capacity Without Energy, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-federal Resources, Unanticipated Load Service, Real Power Losses, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest. This rate schedule is not available for sales of non-firm power outside of the region.

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

Effective October 1, 2025, this rate schedule supersedes the FPS-24 rate schedule. Sales under the FPS-26 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills will be rendered and payments due pursuant to the GRSPs and billing process.

2. Firm Power and Capacity Without Energy

2.1 Flexible Rates and Billing Determinants

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

3. Shaping Services

3.1 Rates and Billing Determinants

The charge for Shaping Services will be the applicable rate(s) times the applicable Billing Determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and Billing Determinant(s) for use of Shaping Services will be as established by BPA or as mutually agreed by BPA and the customer.

4. Reservations and Rights to Change Services

4.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services will be the applicable rate(s) times the applicable Billing Determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and Billing Determinant(s) for Reservation and Rights to Change Services will be as established by BPA or as mutually agreed by BPA and the customer.

5. Reassignment or Remarketing of Surplus Transmission Capacity

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

5.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity will be the applicable rate(s) times the applicable Billing Determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and Billing Determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity will be as established by BPA or as mutually agreed to by BPA and the customer.

6. Other Capacity, Energy, and Scheduling Products and Services

Power Services may sell energy or capacity (including energy or capacity provided to balancing authorities and transmission providers, other than the BPA Balancing Authority, for use as ancillary services) and power scheduling products and services under this rate schedule. Such products and services may include, but are not limited to: (1) firm energy with negotiated curtailment rights; (2) resource support and scheduling services for non-federal resources not eligible for services under Section 7 of this FPS rate schedule; (3) reserve-based products and services (including but not limited to operating reserves, imbalance energy, frequency response reserves, and regulation for use outside the BPA Balancing Authority Area); and (4) non-firm energy within the region.

6.1 Rates and Billing Determinants

Rate(s) and Billing Determinant(s) applicable to such products and services will be as specified by BPA or as agreed to by BPA and the customer. The charge(s) for these services will be the applicable rate(s) times the applicable Billing Determinant(s) pursuant to the agreement between BPA and the customer.

7. Services for Non-Federal Resources

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

Customers that have elected to take TSS/TCMS for their non-federal resources are subject to the TSS and TCMS Charges specified in GRSP II.I.5.

7.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.I.4.

7.3 Resource Remarketing Service (RRS)

Customers that have requested and have been granted permission to take RRS for their non-federal resources will receive the RRS credit specified in GRSP II.I.7.

8. Unanticipated Load Service

The Unanticipated Load Service Charge under the FPS-26 Rate Schedule, specified in GRSP II.M.4, is applicable to the sale of firm power to serve Unanticipated Loads resulting from a request for service under Section 9(i) of the Northwest Power Act. 16 U.S.C. § 839f(i).

9. Real Power Losses

Power Services may sell energy and capacity to BPA Transmission customers for Real Power Loss returns as defined by BPA Transmission Services. If a customer chooses to purchase losses from Power Services, then the customer must contract with Power Services.

9.1 Energy Rates and Billing Determinants

9.1.1 Energy Rate

The energy rate for Real Power Losses will be the greater of 0 and the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

9.1.2 Energy Billing Determinants

For BPA Transmission customers taking Point-to-Point (PTP) transmission service the Energy Billing Determinant will be the hourly scheduled energy amounts, in kilowatthours, multiplied by the applicable loss factor(s) specified in BPA's Open Access Transmission Tariff (OATT), Schedule 11. For BPA Transmission customers taking Network Integration Transmission (NT) service the Energy Billing Determinant will be the hourly non-federal resource and/or Slice output schedule amounts, in kilowatthours, multiplied by the applicable loss factor(s) specified in BPA's OATT, Schedule 11.

9.2 Capacity Rate and Billing Determinants

The Capacity Rate for Real Power Losses is 14.73 mills/kWh. The monthly Capacity Billing Determinant will be the applicable Billing Determinant, in kilowatthours, used to calculate the Energy Charge for Real Power Losses described above in Section 9.1.2.

10. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table and/or as specified by BPA or as agreed to by BPA and the customer.

GRSP II.	Adjustments, Charges, and Special Rate Provisions
I.4	Forced Outage Reserve Service (FORS)
I.5	Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)
I.7	Resource Remarketing Service (RRS)
M.4	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
Z	Cost Contributions
AB	Washington Cap-and-Invest Program Charge

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

INDEX

Page

GENERAL RATE SCHEDULE PROVISIONS

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

A. Approval of Rates

BPA has requested that the Federal Energy Regulatory Commission approve these rate schedules and GRSPs effective October 1, 2025. All rate schedules will remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The 2026 Power Rate Schedules and associated GRSPs supersede BPA's 2024 Power rate schedules, which became effective October 1, 2023, to the extent stated in the Availability section of each rate schedule. The schedules and these GRSPs will be applicable to all BPA contracts, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: The Bonneville Project Act (Pub. L. No. 75-329), *codified at* 16 U.S.C. § 832 *et seq.,* the Regional Preference Act (Pub. L. No. 88-552), *codified at* 16 U.S.C. § 837 *et seq.*, the Transmission System Act (Pub. L. No. 93-454), *codified at* 16 U.S.C. § 838 *et seq.,* the Northwest Power Act (Pub. L. No. 96-501), *codified at* 16 U.S.C. § 839 *et seq.,* and the Energy Policy Act of 1992 (Pub. L. No. 102-486), *codified at* 16 U.S.C. § 824(i)-(l).

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

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

C. Bill Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge will be applied each day to any unpaid balance. The late payment charge will be equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus 4 percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365. The customer will pay by electronic funds transfer using BPA's established procedures.

D. Notices

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

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

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

This set of Supplemental Guidelines augments the BPA Transmission Services "Facility Ownership and Cost Assignment Guidelines," as amended or superseded (Transmission Services Guidelines), currently posted at: https://www.bpa.gov/-/media/Aep/transmission/interconnection/bpa-facility-ownership-and-cost-assignment-guidelines.pdf

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

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

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

Supplemental Guideline Regarding Directly-Assigned Facilities

For new facilities or new service over existing third-party transmission provider facilities that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses such that BPA is not responsible for losses across such directly assigned facilities. Loss calculations should be similar whether the customer or the transmission provider owns the directly assigned facilities.

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

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

Supplemental Guidelines Regarding Construction Option

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

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

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

Wholesale Distribution Facilities Beyond the Step-Down Substation

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

<u>Customer Arrangements Directly with the Third-Party Transmission Provider</u>

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

F. Metering Usage Data Estimation Provision

Pursuant to Section 15.1 of the CHWM Contract for the Load Following product, BPA will apply the Meter Usage Data Estimations procedures posted on the BPA Metering website.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. RHWM Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge Billing Determinant, described in Section 2.1.3.2 of the PF-26 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC values for the FY 2026, 2027, and-2028 rate period are shown in Table A below.

Table A
FY 2026, 2027, and -2028 RHWM Tier 1 System Capability

Month	RT1SC in kWh	
	HLH	*LLH*
October	2,586,042,733	1,564,244,876
November	3,205,599,205	2,100,406,908
December	3,866,898,527	2,165,586,646
January	4,011,749,289	2,352,993,457
February 2026 and 2027	3,227,640,860	1,844,484,668
February 2028 (leap year)	3,341,393,692	1,901,361,084
March	3,606,210,294	1,938,664,499
April	2,645,914,048	1,651,419,692
May	3,367,621,437	2,193,835,990
June	3,702,040,956	1,978,169,776
July	3,203,673,896	1,852,204,907
August	3,447,466,690	1,738,937,744
September	2,507,044,492	1,520,820,254

B. Low Density Discount (LDD)

1. Application and Definitions

For eligible customers, as defined in Section 2 below, a Low Density Discount (LDD) will be applied each billing month to the PF-26 Composite Customer Charge, PF-26 Non-Slice Customer Charge, PF-26 Load Shaping Charge, PF-26 Load Shaping Charge True-Up Adjustment, PF-26 Demand Charge, the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). The LDD also applies to eligible customers under the PF-26 Melded rate schedule and the NR-26 rate schedule. The LDD will be applied to only those charges listed in this GRSP II.B.

For Load Following and Block purchases, the applicable discount percentage will apply to all charges for purchases by the customer under the Tier 1 rates (Composite Customer Charge, Non-Slice Customer Charge, Load Shaping Charge, Load Shaping Charge True-Up Adjustment, Demand Charge, and Risk Adjustments). The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

An LDD dollar benefit will be calculated by BPA for Slice/Block purchases as though it were a Load Following purchase. BPA will use the customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the customer's monthly power bills over the next 12 months. The applicable discount percentage will also be applied to the customer's monthly billed risk adjustments, if any. The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

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

The calculation of the ratios below will be based on calendar year data the customer provides from its annual financial and operating reports (*e.g.,* Rural Utilities Service Financial and Operating Report – Electrical Distribution, National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (CFC Form 7), audited financial report, or annual report). The provided annual financial and operating reports will include the customer's Total Retail Load, depreciated electric plant, number of consumers, pole miles of distribution lines, total kilowatthours sold, and total electric retail sales revenue. The annual financial and operating report is to be enclosed with the customer's calendar year data if not previously submitted to BPA. The customer will certify that the data submitted is true and correct.

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

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

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

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

(a) The Kilowatthour/Investment (K/I) Ratio

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

(b) The Consumers/Pole (C/M) Miles Ratio

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

"Consumers" means the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) are counted on the basis of the number of residences served. If one meter serves two residences, then two consumers are counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer. Security or safety lights billed to a residential consumer will not be counted as an additional consumer. Additional meters used for net metering consumers will not be counted as an additional consumer. Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

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

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

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

2. Eligibility Criteria

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

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

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

(c) The customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 44.76 mills/kWh for FY 2026, FY 2027 and FY 2028.

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

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

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

3. Determination of Eligible Discount percentage

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

Table B
LDD Eligible Discount percentage

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

4. LDD Phase-In Adjustment

If the customer satisfies the eligibility criteria in Sections 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than 0.5 of 1 percentage point, the applicable eligible discount percentage will be one of the following amounts:

(a) the existing eligible discount percentage plus a maximum of 0.5 percent if the calculated eligible discount percentage exceeds the existing discount; or

(b) the existing eligible discount percentage minus a maximum of 0.5 percent if the calculated eligible discount percentage is less than the existing discount.

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

The customer is not eligible to receive any discount, effective each October, if the customer fails to meet the eligibility criteria in Sections 2(a) through (e) above. If the customer is eligible to receive a discount in a year following a year in which the customer was not eligible to receive the discount, then the 0.5 percent phase-in adjustment described above will apply to the most recent eligible discount.

Customers receiving the LDD for the first time will receive the full discount amount as determined in Section 3.

When determining the LDD percentage pursuant to Sections 3 and 4, the calculations will not include any Additional Adjustment for Very Low Densities as determined in Section 5.

5. Additional Adjustment for Very Low Densities

If a customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after the annual determination of the eligible discount percentage pursuant to Sections 3 and 4 above, an additional 0.5 percent will be added to the customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent.

6. Applicable Discount for Customers with Above-RHWM Load

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

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

Where:

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

eligibleLDD = the customer's eligible discount percentage as computed according to Sections 2 through 5 above

adjTRL = the customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the RHWM Process for the applicable fiscal year

RHWM = the customer's Rate Period High Water Mark for the applicable fiscal year

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

7. Treatment for Joint Operating Entity

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

(a) Each individual utility member's Demand Billing Determinant is calculated as if such member were not a member of a JOE.

(b) The Demand Billing Determinants for all individual utility members are summed.

(c) The individual utility members' calculated Demand Billing Determinants are scaled (up or down) so that the sum of all individual utility members' calculated Demand Billing Determinants equals the JOE's Demand Billing Determinant.

(d) The demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled Demand Billing Determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 Demand Charge.

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

C. Irrigation Rate Discount

1. Discount for Eligible Customers

Section 3 of Exhibit D of the CHWM Contracts describes Irrigation Rate Mitigation (IRM), and Section 10.3 of the Tiered Rate Methodology describes an Irrigation Rate Mitigation Product (IRMP). Both the IRM and IRMP are implemented through the Irrigation Rate Discount (IRD) set forth in this provision.

In May, June, July, August, and September, an eligible customer will have the Irrigation Rate Discount of 11.96 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

The eligibility amounts for the Irrigation Rate Discount are set forth in Section 3.1 of Exhibit D of the CHWM Contracts and are subject to the True-Up process referenced in Section 3.2 of the Contract and described more fully below.

For a Load Following or Block customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping Billing Determinant. For a Slice/Block customer, the energy purchased at Tier 1 rates will be equal to the sum of the customer's monthly Block purchase at Tier 1 rates plus the customer's Slice percentage multiplied by the monthly/diurnal RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a JOE will be calculated based on individual utility members' loads and billed to the JOE and designated for each eligible utility.

BPA requires a participating customer to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The customer may use its Energy Efficiency Incentive fund for this purpose.

2. Metering Requirements

The customer is required to read irrigation meters at the beginning of May and after the end of the Irrigation Rate Discount season (September 30). The customer shall provide to BPA monthly metered irrigation load information for the months of May through September in a form that is acceptable to BPA no later than October 31 of each year to ensure a timely True-Up calculation.

3. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. The actual metered irrigation kilowatthour amounts submitted by the customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts.

If the sum of a customer's May through September measured irrigation load is less than the sum of the May through September billed irrigation load amounts, a True-Up calculation is required. However, if the sum of a customer's May through September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a True-Up calculation is not applicable.

The True-Up is calculated as follows. The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the True-Up reimbursement. The True-Up reimbursement will appear as a charge on a subsequent monthly power bill.

D. Demand Rate Billing Determinant Adjustments

BPA may adjust customers' bills after the fact for changes to Demand Charge Billing Determinants, as described below.

1. Extreme Load Shift Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

If a customer's monthly CDQ-adjusted HLH load factor (aHLH divided by the quantity (i) Tier 1 CSP minus (ii) CDQ minus (iii) SuperPeak) is less than 55 percent, BPA may recompute a customer's Demand Billing Determinant for the month. The month will first be separated into two or more partial-month periods using the extreme load shift events that occur during the month as demarcations for the periods. For each partial-month period, a separate demand value will be calculated using the same arithmetic method used to compute the customer's Demand Billing Determinant for the full month, but such calculation will use only the peak and energy consumed during each partial-month period. If BPA agrees to an adjustment, the largest of the partial-month demand values among the partial-month periods will be used as the customer's Demand Billing Determinant for the entire month.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for an extreme load shift Demand Billing Determinant recalculation. BPA shall not be responsible for Demand Billing Determinant recalculation without customer notification. BPA will not consider a customer request to recalculate a Demand Billing Determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

2. Recovery Peak Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

The demand CSP may be reduced by the kilowatt difference between the CSP resulting from a Recovery Peak and the next highest HLH peak during the month that is not a Recovery Peak.

Recovery Peak will mean an extraordinary CSP measured in a customer's load following return to service from an outage. A Recovery Peak for which BPA would consider a Recovery Peak Demand Billing Determinant Adjustment must have all three of the following characteristics:

(1) the CSP occurred during one of the two (2) hours immediately following restoration of service after an outage due to an Uncontrollable Force, provided that the outage lasted for two hours or more;

(2) the outage reduced the utility's Total Retail Load (TRL) by 25 percent or more; and

(3) the Demand Billing Determinant resulting from such a CSP is 10 percent or more of those CSP kilowatts.

In determining the 25 percent threshold, the TRL reduction is computed by comparing the TRL measured during any hour of the outage to the TRL measured in the hour ended immediately prior to the hour in which the outage began. BPA may consider evidence that an observed CSP is not extraordinary. Such evidence may include that substantial restoration of service occurred more than two hours prior to the potential Recovery Peak hour, the hourly load patterns before and after the outage, and loads of similarly situated customers that did not experience a simultaneous outage due to an Uncontrollable Force.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for a Demand Billing Determinant recalculation. BPA shall not be responsible for Demand Billing Determinant recalculation without customer notification. BPA shall not consider a customer request to recalculate a Demand Billing Determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

E. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to customers purchasing the Load Following product in specific circumstances. The Adjustment will be determined following each fiscal year of the rate period and will appear on the customers' power bills.

1. Load Shaping Charge True-Up Rate

Fiscal Year	Rate in mills/kWh
2026	3.88
2027	3.88
2028	3.88

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See Appendix A, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

2. Load Shaping Charge True-Up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each customer determines whether the customer may be eligible for a True-Up Charge or Credit.

Annual Deviation = *Actual Annual Tier 1 Load (measured)* *minus* *TOCA Load (calculated)*

TOCA Load is the annual amount of energy that is used to calculate the customer's TOCA. If the customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.G, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-Up; see Special Implementation Provision, Section 3 below.

(b) True-Up Credit

If Annual Deviation is positive, the customer is eligible for a True-Up Credit if Above-Forecast Amount is positive (greater than zero).

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

If the Above-Forecast Amount is positive, the True-Up Credit Billing Determinant equals negative one (-1) multiplied by the lesser of:

(1) Annual Deviation, or
(2) Above-Forecast Amount.

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

(c) True-Up Charge

If Annual Deviation is negative, the customer may be subject to a True-Up Charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation, the customer is subject to a True-Up Charge.

True-Up Charge *Billing Determinant*	=	*Absolute value of the Annual Deviation* *minus* *Above-RHWM Load*

The True-Up Charge Billing Determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

- the customer has Above-RHWM Load, and
- the customer has an Above-Forecast Amount greater than zero.

If both these conditions are met, the customer may be eligible for an additional Load Shaping True-Up Credit.

If the Annual Deviation is negative or zero and the absolute value of the Annual Deviation is less than the customer's Above-RHWM Load, then the Special True-Up Credit Billing Determinant is negative one (-1) multiplied by the least of (i) the customer's Above-RHWM Load; (ii) the Above-RHWM Load minus the absolute value of the Annual Deviation; or (iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-Up Credit Billing Determinant is negative one (-1) multiplied by the lesser of (i) the customer's Above-RHWM Load; or (ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is equal to the Load Shaping Charge True-Up rate multiplied by the sum of (i) the True-Up Credit Billing Determinant; (ii) the True-Up Charge Billing Determinant; and (iii) the Special True-Up Credit Billing Determinant.

The final Load Shaping Charge True-Up Adjustment for each customer shall be applied as either a one-month credit (if the adjustment is negative) or a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping customers have the option to pay the entire charge in one month. There will be no interest component applied to the Load Shaping Charge True-Up payment schedule.

F. Tier 2 Rate TCMS Adjustment

This adjustment will recover the cost BPA incurs as a result of a transmission event (in the form of either a planned transmission outage or a transmission curtailment) along the transmission path, between the Point of Receipt and the Point of Delivery, used to deliver energy associated with the power purchases for the Tier 2 cost pools. In such a transmission event situation, a TCMS adjustment will be applied to customers' bills if they purchase power at the applicable Tier 2 rate. The method used to calculate the aggregate TCMS adjustment is specified in GRSP II.I.5(c) and (d). The aggregate TCMS adjustment will be allocated to customers based on each customer's proportional energy share of the applicable Tier 2 cost pool.

G. TOCA Adjustment

For each customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-26 7(i) process and will be made available to the customer prior to October 1, 2025. A customer's TOCA for a fiscal year will be revised only as specified below.

The customer's adjusted TOCA will be used to establish the Billing Determinant for the Composite, Slice, and Non-Slice customer charges for the relevant fiscal year. No other customer's TOCA will be affected by this TOCA adjustment.

If a TOCA is modified after the October power bill is issued for the fiscal year to which the modified TOCA applies, the customer will be billed retroactively to October 1 of that fiscal year through a one-time billing adjustment. The billing adjustment will be calculated as (i) the sum of the amount billed for the months prior to any mid-year

TOCA adjustment minus (ii) the sum of the amount that should have been billed for those same months with the mid-year adjusted TOCA. A positive calculation is a credit to the customer, and a negative calculation is a charge to the customer.

1. Load Following Customers

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

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

If the resulting TOCA differs from the TOCA calculated in the BP-26 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-26 7(i) process.

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

If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Additionally, if the customer's Existing Resource amounts in Exhibit A have changed in accordance with its CHWM Contract, then the customer's TOCA may be updated for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block customer in four circumstances:

(a) If the customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-26 7(i) process, the customer's TOCA will be recalculated for that fiscal year using the customer's Annual Net Requirement.

(b) If the customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-26 7(i) process is less than its RHWM, then the customer's TOCA will be recalculated for that fiscal year using the customer's RHWM.

(c) If a customer's Annual Net Requirement changes within a fiscal year due to a change in the customer's Specified Resource amounts within a fiscal year, then the customer's TOCA will be recalculated.

(d) If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

H. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to Section 7(c)(3) of the Northwest Power Act, a DSI customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. 16 U.S.C. § 839e(c)(3). The DSI Operating Reserve – Supplemental is a contractual right for BPA to interrupt DSI load being served with Industrial Firm Power in a megawatt amount equal to 10 percent of the amount of power scheduled for delivery at the time the interruption request occurs. The Minimum DSI Operating Reserve – Supplemental provided by a DSI customer must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, including the following:

1. The interruptible load must be offline or the increased generation must be online within 10 minutes after a call from BPA.
2. In the event of a system disturbance, the interruptible load or increased generation must be accessible in advance of any need for BPA to request reserves from other Northwest Power Pool members.
3. The interruptible load must be available to be offline for up to 105 minutes, or increased generation must be available to be online for up to 105 minutes.
4. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

Optional Reserves. BPA is not obligated to purchase any DSI Reserves(s) beyond the Minimum DSI Operating Reserve – Supplemental. However, BPA's contracts with DSI customers contain a contingent right to purchase additional reserves to the extent they are needed for operational purposes and can be made available by the customer. These contract provisions are designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the price for such reserves based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost-effective, the maximum amount to be paid by Power Services for Operating Reserves – Supplemental is capped at $4.99 per kW per month.

The availability of optional DSI Reserve(s) purchased by BPA must be consistent with NERC, WECC, and NWPP standards and criteria specific to Balancing Authority Area Operating Reserve Requirements, including the following characteristics:

1. The interruptible load must be offline or the increased generation online within the period specified for the applicable DSI Reserve purchased.
2. The interruptible load or increased generation must be accessible in advance of any need to request reserves from other Northwest Power Pool members.

In addition to these two characteristics, the issues identified below will guide consideration of when BPA may pay the maximum value for DSI Reserves:

1. The degree to which BPA has discretion with respect to when and how to use the reserves and to determine what resources to call on in the event of system disturbance or for some other purpose specified in any negotiated agreement for optional reserves.
2. Duration of time the interruptible load is available to be offline or increased generation is available to be online.

I. Resource Support Services and Transmission Scheduling Service

Unless stated otherwise, the resource generation amounts used in the calculations below that are from the customer's CHWM Contract are (1) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); (2) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.2(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.2(3) of Exhibit D (Exhibit D hourly average planned amounts).

1. Diurnal Flattening Service (DFS) Charges

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as defined in the customer's CHWM Contract. When DFS charges are coupled with Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service.

DFS will apply to the non-federal resource the customer is applying to its load and any portion of the resource remarketed by BPA.

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's RAM2026 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of hourly generation in excess of average monthly/diurnal Exhibit D planned amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in GRSP II.I.2(a)(1) below. The monthly/diurnal results are summed for the year and divided by the total Exhibit D planned amounts for that same year to calculate the DFS energy rate.

(2) DFS Energy Billing Determinant

The DFS Energy Billing Determinant is the actual generation for the particular resource during the billing month. The actual generation amounts are either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag.

(3) Calculation of DFS Energy Charge

For each resource, the DFS Energy Charge is calculated by multiplying the DFS energy rate by the DFS Energy Billing Determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 demand rates shown in Section 2.1.2.1 of the PF-26 rate schedule.

(2) DFS Capacity Billing Determinant

The DFS Capacity Billing Determinant is equal to the resource's monthly average Exhibit D HLH planned amounts in one year minus the calculated monthly firm capacity of the resource for that same year.

The RSS module of BPA's RAM2026 calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) Calculation of DFS Capacity Charge

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

- the annual sum of (i) each month's DFS Capacity rates multiplied by (ii) that same month's DFS Billing Determinants; or
- the annual average Exhibit D planned amount multiplied by the sum of the monthly PF Tier 1 demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, such that if a customer can no longer apply the resource to load or if its application to load is delayed, the Capacity Charge will still apply.

2. Resource Shaping Charge (RSC) and Resource Shaping Charge Adjustment

(a) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in Section 2.1.3.1 of the PF-26 rate schedule.

(2) Resource Shaping Billing Determinant

The Resource Shaping Billing Determinant for each resource is equal to: (1) the annual average Exhibit A amount converted to a monthly/diurnal shape (in MWh) using the corresponding monthly/diurnal hours for the same year; minus (2) the monthly/diurnal Exhibit D planned amounts or the monthly/diurnal Exhibit A amounts. Generally, RSC does not apply to small, non-dispatchable resources as identified in the customer's CHWM Contract.

When DFS is provided to a resource to which RRS also applies, the Billing Determinant for each resource is equal to: (i) the sum of the annual average Exhibit A amounts and Resource Remarketing amounts in Exhibit D for the same year; minus (ii) the monthly/diurnal Exhibit D planned amounts.

(3) Calculation of Resource Shaping Charge

For each resource, the RSC is calculated by multiplying the Resource Shaping rate by the Resource Shaping Billing Determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge.

(b) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the Billing Determinant is equal to Exhibit D planned amounts minus the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The calculation of the RSC Adjustment Billing Determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and unauthorized increases (UAIs) in the determination of actual generation.

(3) Calculation of Resource Shaping Charge Adjustment

For each resource, the RSC Adjustment is calculated by multiplying the RSC Adjustment rate by the RSC Adjustment Billing Determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

3. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following customer that dedicates the entire output of a hydroelectric Existing Resource with (1) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and (2) a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

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

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) SCS Energy Billing Determinant

For each resource, the Energy Billing Determinant is equal to the monthly/diurnal Exhibit A MWh amounts minus the actual monthly/diurnal generation amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The actual generation will include energy amounts provided through TCMS.

(3) Calculation of SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is calculated by multiplying the SCS energy rate by the SCS Energy Billing Determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the customer will receive a credit. If the actual generation is less than the Exhibit A amount, the customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-26 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the Billing Determinant is the monthly average HLH Exhibit A amount multiplied by the forced outage rating.

(3) Calculation of SCS Administrative Charge

For each resource, the SCS Administrative Charge is calculated by multiplying the SCS Administrative rate by the SCS Administrative Billing Determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative Charge will be specified in Exhibit D of the customer's CHWM Contract.

4. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to customers that have a qualifying resource that experiences a forced outage.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

(2) FORS Capacity Billing Determinant

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

(3) Calculation of FORS Capacity Charge

For each resource, the FORS Capacity Charge is calculated by multiplying the FORS Capacity rate and the FORS Capacity Billing Determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, so that if a customer can no longer apply the resource to load or if its application to load is delayed, the Capacity Charge will still apply.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the hourly Load Aggregation Point (LAP) prices for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff during hours of the forced outage. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest. If any price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

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

(2) FORS Energy Billing Determinant

The FORS Energy Billing Determinant is the total actual replacement generation a resource requires to meet the Exhibit D hourly average planned amount, subject to the FORS energy limits specified therein.

(3) Calculation of FORS Energy Charge

For each resource, the monthly FORS Energy Charge is calculated by multiplying the FORS energy rate by the FORS Energy Billing Determinant.

5. Transmission Scheduling Service (TSS) Charges and Transmission Curtailment Management Service Charge (TCMS)

TSS is a service provided by Power Services to undertake certain scheduling obligations on behalf of the customer. There are two available service levels of TSS: full service (TSS-Full) and partial service (TSS-Partial). TCMS is a feature of TSS (both TSS-Full and TSS-Partial) under which BPA provides either replacement transmission or power to customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) Transmission Scheduling Service Full Service (TSS-Full) Charge

(1) TSS-Full Rate

Fiscal Year	Rate in mills/kWh
2026	0.12
2027	0.12
2028	0.12

(2) TSS-Full Billing Determinant

The TSS-Full Billing Determinants are the annual Exhibit A amounts in kilowatthours. When TSS-Full is provided to a resource to which RRS also applies, the TSS-Full Billing Determinant for each resource is (1) the annual Exhibit A amounts in kilowatthours plus (2) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS-Full Charge

For each eligible resource, the TSS-Full Charge is calculated by multiplying the TSS-Full rate and the TSS-Full Billing Determinant for each month of the rate period (or an individual fiscal year if this service applies only in one fiscal year). The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge. The charge is subject to a cap (not including OATI registration fee recovery adjustments described below). Charges for Specified Resources and Unspecified Resource Amounts serving Above-RHWM Load are capped such that if the annual cost to the customer using the TSS rate exceeds $1,038/month, then the monthly charge is capped at $1,038/month. Charges for Unspecified Resource Amounts serving NLSL and 9(c) export decrement obligations are capped such that if the annual cost to the customer using the TSS rate exceeds $3,115/month, then the monthly charge is capped at $3,115/month.

For each TSS-Full customer, BPA will determine the number of resources receiving TSS-Full. Then the $200 annual OATI registration fee is applied evenly across those resources and divided by 12 months in the applicable fiscal years of the rate period.

(b) Transmission Scheduling Service Partial Service (TSS-Partial) Charge

(1) TSS-Partial Rate

Fiscal Year	$ per TSS-Partial Event
2026	246
2027	246
2028	246

(2) TSS-Partial Billing Determinant

The TSS-Partial Billing Determinant is the total number of TSS-Partial events that occur within a month. Each of the following is considered a single TSS-Partial event:

(A) a customer, or its scheduling agent, fails to carbon copy (CC) Power Services on a schedule, except if the power being scheduled was purchased from Power Services, including Slice output, and Power Services was included in the market path on the tag; or
(B) a day that a customer has a TCMS charge.

(3) Calculation of TSS-Partial Charge

The TSS-Partial Charge is calculated by multiplying the TSS-Partial rate by the TSS-Partial Billing Determinant for each month of the rate period.

(c) TCMS Charge if Replacement Power is Provided

If BPA purchases replacement power during a transmission event for a resource supported by TCMS, then the TCMS Charge will be the cost of such purchased power. If BPA does not purchase replacement power, then the TCMS Charge will be calculated in accordance with the sections below.

(1) TCMS Rate

The TCMS rate will be the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour the event occurred. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest. If any price is less than zero, the TCMS energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS Billing Determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) Calculation of TCMS Charge

The TCMS Charge is calculated by multiplying the TCMS rate by the TCMS Billing Determinant for each month of the rate period.

(d) TCMS Charge if Alternative Transmission is Provided

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

6. Grandfathered Generation Management Service (GMS)

GMS allows a Load Following customer that dedicated the entire output of an Existing Resource that received GMS during Subscription to run that resource against load and offset its Tier 1 Load.

(a) GMS Reservation Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-26 rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the GMS Reservation Billing Determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity Billing Determinant in GRSP II.I.1(b)(2).

(c) Calculation of GMS Reservation Fee

For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation rate and the GMS Reservation Billing Determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The GMS Reservation Fee will be specified in Exhibit D of the customer's CHWM Contract.

7. Resource Remarketing Service (RRS) Credits

RRS is an optional service to provide a Remarketing Credit to customers that have a qualifying non-federal resource to which DFS applies that is expected to generate more than a customer's Above-RHWM Load. The non-federal resource amounts used in these calculations are those specified in the customer's CHWM Contract Exhibit D RRS section (Exhibit D RRS amounts).

(a) RRS Credit

(1) RRS Rate

For each non-federal resource, the rate will be the Remarketing Value in GRSP II.K.3.

(2) RRS Billing Determinant

For each non-federal resource, the RRS Billing Determinant is the Exhibit D RRS amount.

(3) Calculation of RRS Credit

For each non-federal resource, the RRS Credit is calculated by multiplying the RRS rate and the RRS Billing Determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit.

(b) RRS Fee

The fee for providing RRS to customers is determined on a case-by-case basis.

J. NR Services for New Large Single Loads (NLSLs)

NR Services for NLSLs is a required service applicable to Load Following customers serving NLSLs with non-federal resources. All NR ESS charges and credits are calculated using the aggregate of the NLSLs if there are multiple facilities managed by a single operator.

1. NR Energy Shaping Service (ESS) for NLSL Charge

(a) NR ESS Capacity Charge

Customers taking NR ESS will be assessed the NR ESS Capacity Charge. The default level of service is 2%. A customer may elect a higher level of service (3%, 4% or 5% level of service) by providing written notice to BPA no later than February 1, 2025. The default or elected level of service applicable to the customer ("Level of Service %") shall apply for the entire rate period. The monthly NR ESS Capacity Charge is calculated using the following formula:

$$NRESS_{Capacity} = MonthlyPeak \times LevelofService\% \times DemandRate$$

Where:

$NRESS_{Capacity}$ = the monthly NR Energy Shaping Service Capacity Charge

$MonthlyPeak$ = the measured maximum actual hourly load of the NLSLs for a month in kWs

$LevelofServcie\%$ = 2 percent or the Level of Service % elected by the customer

$DemandRate$ = the applicable monthly NR Demand Rate as specified in the NR-26 rate schedule, Section 2.2.1

A monthly check will be performed to verify that the customer's Actual Capacity Use in any hour of the month did not exceed the monthly amount of capacity purchased from BPA. The monthly amount of capacity purchased from BPA in a month is equal to the Level of Service % plus four percent multiplied by the $MonthlyPeak$. The Actual Capacity Used in an hour is equal to the actual hourly kWh load of the NLSLs for that hour minus the non-federal resources supplied in that same hour. The Unauthorized Increase Charge (UAI) (GRSP II.N) shall apply in any hour where the Actual Capacity Used exceeds the monthly amount of capacity purchased from BPA after being rounded down to a whole MWh.

(1) NR Data Sharing Discount

A 10 percent NR Data Sharing Discount will be applied to the monthly NR ESS Capacity Charge if the customer meets the following Data Sharing Requirements each hour of the month:

(A) Resource Forecast

NR ESS customer receiving the NR Data Sharing Discount shall provide BPA with a forecast of the energy amount of non-federal resource supplied in MWh for each hour to each NLSL, or aggregation of NLSLs served by a single Load Following customer, 7-calendar days in advance of the operating day. To provide this resource forecast to BPA, customers shall enter the hourly amount of energy to be supplied by non-federal resource(s) into BPA's ISAAC scheduling system. Provision of this forecast is for the purposes of BPA maintaining an appropriate level of generation capacity and does not alter requirements for the resource deliveries to be scheduled with all appropriate transmission service providers.

(B) Load Forecast

NR ESS customer receiving the NR Data Sharing Discount shall provide BPA with a forecast of the energy amount of the load in MWh for each hour for each NLSL, or aggregation of NLSLs served by a single Load Following customer, 7-calendar days in advance of the operating day. To provide this load forecast to BPA, customers shall enter the hourly amount of energy to be consumed by the load for each hour into BPA's ISAAC scheduling system or another mechanism of BPA's choosing. Provision of this load forecast is for the purposes of BPA maintaining an appropriate level of generation capacity and does not alter requirements for the load to be scheduled with all appropriate transmission service providers, if applicable.

No later than 90-days prior to October 1, 2025, a customer may request a pilot implementation of these Data Sharing Requirements for a duration of up to 60-days ahead of the effective date and BPA will make best efforts to implement such pilot period.

Customers are eligible for the NR Data Sharing Discount by providing these forecasts consistent with the terms above.

(2) **NR ESS Capacity Cost Offset**

A customer purchasing NR ESS and receiving the NR Data Sharing Discount may be eligible to further offset its NR ESS Capacity Charge by providing BPA access to capacity, through a demand or a resource response, based on terms and conditions agreed to in an Exhibit to an WSPP Enabling Agreement between BPA and the customer.

(b) **NR ESS Energy Charge**

The energy component of the NR Energy Shaping Service either credits or debits the customer for the difference between energy amounts supplied by the customer's non-federal resources serving NLSLs and the measured actual load of the NLSLs in every hour. It is applied in periods where a NR ESS Power Persistent Deviation has not occurred. The NR ESS Energy Charge can be either positive or negative and is the calculated as the NR ESS Energy Billing Determinant multiplied by the NR ESS Energy Rate.

(1) **NR ESS Energy Billing Determinant**

The NR ESS Energy Billing Determinant is equal to (1) the total measured actual load of the customer's NLSL(s) in an hour minus (2) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources in that same hour. The Billing Determinant for any hour can be positive or negative.

(2) **NR ESS Energy Rate**

The NR ESS Energy Rate is equal to the hourly Load Aggregation Point (LAP) price for BPA, or the LAP price applicable for the area in which the NLSL is located, as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the same hour as the calculated NR ESS Energy Billing Determinant. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

(c) **NR ESS Power Persistent Deviation Charge**

Load Following customers serving NLSLs with non-federal resources will be subject to charges for persistent over- or under-scheduling of such non-federal resource to its NLSLs. Applicability will vary on whether the customer is receiving the NR Data Sharing Discount. When the NR ESS Power Persistent Deviation Charge is applied, the NR ESS Energy Charge shall not be applied.

NR ESS Power Persistent Deviation Charge is calculated as the sum of the NR ESS Power Persistent Bill Determinant multiplied by the NR ESS Power Persistent Deviation Rate for each applicable hour in the month.

The NR ESS Power Persistent Deviation Billing Determinant is equal to (1) the total measured actual load of the customer's NLSL(s) in an hour minus (2) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources in that same hour net of (3) the energy amounts in that same hour applied to the calculation of the Unauthorized Increase Charge (GRSP II.N). The Billing Determinant for any hour can be positive or negative.

(1) NR ESS Power Persistent Deviation Charge with NR Data Sharing Discount

The following measurements will be used to determine if the NR ESS Power Persistent Deviation Charges will apply for customers *with* an NR Data Sharing Discount:

(A) Under Schedule

The NR ESS Power Persistent Deviation Charge will apply to all hours in which a positive deviation (*i.e.,* the actual measured load of the NLSLs is greater than the scheduled energy to those NLSLs), exceeds:

(i) both 6 percent of the integrated hourly load rounded down to the next whole MW and 10 MW for four consecutive hours or more of positive deviation; or

(ii) both 1.5 percent of the integrated hourly load rounded down to the next whole MW and 2 MW for 24 consecutive hours or more of positive deviation.

(B) Over Schedule

The NR ESS Power Persistent Deviation Charge will apply to all hours in which the absolute value of the negative deviation (*i.e.,* the actual load of the NLSLs is less than the scheduled energy to those NLSLs), exceeds:

(i) both 1.5 percent of the integrated hourly load rounded up to the next whole MW and 5 MW for 24 consecutive hours or more of negative deviation.

(2) NR ESS Power Persistent Deviation Charge without NR Data Sharing Discount

The following measurements will be used to determine if the NR ESS Power Persistent Deviation Charges will apply for customers *without* an NR Data Sharing Discount:

(A) Under Schedule

The NR ESS Power Persistent Deviation Charge will apply to all hours in which a positive deviation (*i.e.,* the actual measured load of the NLSLs is greater than the scheduled energy to those NLSLs), exceeds:

(i) both 6 percent of the integrated hourly load rounded down to the next whole MW and 10 MW for four consecutive hours or more of positive deviation; or

(ii) both 1.5 percent of the integrated hourly load rounded down to the next whole MW and 2 MW for 24 consecutive hours or more of positive deviation.

(B) Over Schedule

The NR ESS Power Persistent Deviation Charge will apply to all hours in which the absolute value of the negative deviation (*i.e.,* the actual load of the NLSLs is less than the scheduled energy to those NLSLs), exceeds:

(i) both 6 percent of the integrated hourly load rounded up to the next whole MW and 10 MW in each scheduled period for four consecutive hours or more of negative deviation; or

(ii) both 1.5 percent of the integrated hourly load rounded up to the next whole MW and 2 MW in each scheduled period for 24 consecutive hours or more of negative deviation.

(3) NR ESS Power Persistent Deviation Rate

(A) Under Schedule Rate

When an *under schedule* NR ESS Power Persistent Deviation applies (the actual load of the NLSLs is greater than the scheduled energy to those NLSLs), the rate is equal to the greater of (i) 100 mills per kilowatthour, or (ii) 125 percent of the highest hourly Load Aggregation Point (LAP) price as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff during the persistent deviation period. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

(B) Over Schedule Rate

Positive Energy Index. The rate is zero mills per kilowatthour (no credit is given) in hours when an *over schedule* NR ESS Power Persistent Deviation applies (the actual load of the NLSLs is less than the scheduled energy to those NLSLs) and the Load Aggregation Point (LAP) price as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff is *positive*. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

Negative Energy Index. The hourly rate is equal to the Load Aggregation Point (LAP) price as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff in hours where the LAP price is *negative* (resulting in a charge to the customer). In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

(C) Pattern of Conduct

In addition to the conditions of *over* and *under* scheduling as described in section J.1.c above, BPA may apply the NR ESS Power Persistent Deviation Charge for other periods of time if the customer's energy schedules to its NLSL results in a Pattern of Conduct. A Pattern of Conduct is defined as a pattern of under- or over-schedule that would otherwise qualify for the NR ESS Power Persistent Deviation Charge, but is not qualifying for such treatment because of anomalous scheduling behavior that is designed to avoid the charge.

(D) Reduction or Waiver of NR ESS Power Persistent Deviation

BPA, at its sole discretion, may waive all or part of the Power Persistent Deviation Charge if BPA determines (i) the customer took mitigating action(s) to avoid or limit the Power Persistent Deviation, including but not limited to, changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Power Persistent Deviation was caused by extraordinary circumstances.

K. Remarketing

1. Tier 2 Remarketing for Individual Customers

This credit and fee are applicable to customers when BPA is remarketing their Tier 2 rate purchase amounts pursuant to Section 10 of the CHWM Contract.

(a) Tier 2 Remarketing Rate

(1) For Load Following Customers

For each fiscal year, the Tier 2 Remarketing rate will be the Remarketing Value in GRSP II.K.3.

(2) For Slice/Block and Block Customers

After notice is provided by the Slice/Block or Block customer, the rate will be the flat annual equivalent market price forecast, as determined by BPA after the time of the notice, for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities.

(b) Tier 2 Remarketing Billing Determinant

For each applicable Tier 2 rate, the Billing Determinant is (i) the customer's contracted annual Tier 2 amount at such rate plus real power losses, less (ii) the customer's annual Tier 2 load at such rate plus real power losses.

(c) Tier 2 Remarketing Credit

For each customer, the Tier 2 Remarketing Credit is calculated by multiplying the applicable Tier 2 Remarketing rate and the Tier 2 Remarketing Billing Determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) Tier 2 Remarketing Fee

The fee for remarketing customers' Tier 2 amounts is zero in FY 2026–2028.

2. Non-Federal Resource with DFS Remarketing

This credit and fee are applicable to customers when BPA is remarketing their non-federal resources to which DFS applies, pursuant to Section 10 of the CHWM Contract.

(a) DFS Remarketing Rate

For each fiscal year, the DFS Remarketing rate will be the Remarketing Value in GRSP II.K.3.

(b) DFS Remarketing Billing Determinant

For each applicable on-federal resource to which DFS applies, the DFS Remarketing Billing Determinant is (1) the amount of the customer's non-federal resource, as specified in the customer's CHWM Contract Exhibit A, prior to temporary resource removal; less (2) the amount of the customer's non-federal resource needed to meet Above-RHWM Load, as specified in the customer's CHWM Contract Exhibit A, when updated for temporary resource removal.

(c) DFS Remarketing Credit

For each customer, the DFS Remarketing Credit is calculated by multiplying the applicable DFS Remarketing rate and the DFS Remarketing Billing Determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) DFS Remarketing Fee

The DFS Remarketing Fee for a customer with a non-federal resource supported with DFS is zero in FY 2026, FY 2027 and FY 2028.

3. Remarketing Value

For each fiscal year, the Remarketing Value rate will be:

Fiscal Year	Rate in mills/kWh
2026	66.58
2027	63.28
2028	63.54

L. Transfer Service Charges

Transfer Service applies to BPA Power Service customers that are served under non-federal transmission service agreements.

1. Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge will apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for operating reserves for the customer's load served by transfer.

(a) Transfer Service Operating Reserve Rate

(1) The rate for the Transfer Service Spinning Operating Reserve Charge will be equal to the ACS-26 Operating Reserve – Spinning Reserve Service rate.

(2) The rate for the Transfer Service Supplemental Operating Reserve Charge will be equal to the ACS-26 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Service Operating Reserve Billing Determinant

(1) The monthly Billing Determinant for the Transfer Service Spinning Operating Reserve Charge will be the same as that used for the applicable ACS-26 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the Billing Determinant for Power Services' charge will be the amount of the customer's metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

(3) The monthly Billing Determinant for the Transfer Service Supplemental Operating Reserve Charge will be the same as that used for the applicable ACS-26 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the Billing Determinant for Power Services' charge will be the amount of the customer's metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

2. Transfer Service Regulation and Frequency Response Charge

The Transfer Service Regulation and Frequency Response Charge will apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for Regulation and Frequency Response for the customer's load served by transfer.

(a) Transfer Service Regulation and Frequency Response Rate

The rate for the Transfer Service Regulation and Frequency Response Charge will be equal to the ACS-26 Regulation and Frequency Response rate.

(b) Transfer Service Regulation and Frequency Response Billing Determinant

The monthly Billing Determinant for the Transfer Service Regulation and Frequency Response Charge will be the same as that used for the applicable ACS-26 Regulation and Frequency Response rate, except that the load used to calculate the Billing Determinant for Power Services' charge will be the amount of the customer's total load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service Regional Compliance Enforcement Charge

The Transfer Service Regional Compliance Enforcement Rate will apply to Public customers with load outside the BPA Balancing Authority Area.

(a) Transfer Service Regional Compliance Enforcement Rate

	Rate in mills/kWh
All months	0.05

(b) Transfer Service Regional Compliance Enforcement Billing Determinant

The monthly Billing Determinant for the Transfer Service Regional Compliance Enforcement Charge will be the public customer's metered load at points of delivery served by transfer (non-BPA Balancing Authority Area load).

M. Unanticipated Load Service (ULS)

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2025, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2026-2028 rate period. Contractual obligations that result from a request for service under Section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a customer that adds load through retail access, including load that was once served by the customer and returns under retail access. ULS that is used for replacement of a customer's new Specified Resource is available on only a temporary basis for the FY 2026-2028 rate period and only when requested pursuant to the required notice.

The following list includes other sources of Unanticipated Load that will be served by BPA along with the applicable rate schedule under which each type of Unanticipated Load will be served.

- Under PF-26, Unanticipated Load is:
  - Load of a New Public (Load Following customers only)
  - Load annexed from investor-owned utilities by a Public (Load Following customers only)

- Under NR-26, Unanticipated Load is:
  - New Large Single Loads
  - Requirements service requested by investor-owned utilities
- Under FPS-26, Unanticipated Load is negotiated on a case-by-case basis.

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

To start service for Unanticipated Load, the customer must notify BPA three months in advance of the requested service date for load amounts up to 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for Unanticipated Load, the customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the customer's contract for ULS or the conclusion of the rate period on September 30, 2028, whichever occurs first. ULS is a temporary service and may be adjusted annually. For load annexed from investor-owned utilities by a Public (Load Following customers only) served under PF-26 and for resource replacement of a Public Load Following customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 aMW per year. These loads will be included in the customer's Actual Hourly Tier 1 Loads and Actual Monthly/Diurnal Tier 1 Load for billing purposes. Any ULS in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-26 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

(A) the applicable diurnal period PF Tier 1 equivalent energy rate (GRSP II.AA); or

(B) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The Energy Billing Determinant will be the total amount of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand rate is equal to the Demand rate included in Section 2.1.2.1 of the PF-26 rate schedule.

(2) Demand Billing Determinant

The Demand Billing Determinant will be the lesser of:

(A) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month; or

(B) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-26 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

(A) the applicable diurnal period energy rate in Section 2.1.1 of the NR-26 rate schedule; or

(B) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The Energy Billing Determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand rate is equal to the demand rate included in Section 2.2.1 of the NR-26 rate schedule.

(2) Demand Billing Determinant

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

4. Unanticipated Load Service Charge Under the FPS-26 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

(A) the applicable diurnal period Resource Replacement rate that equals the PF Tier 1 Equivalent energy rate (GRSP II.AA) from the same diurnal period; or

(B) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

(2) Energy Billing Determinant

The Energy Billing Determinant is the total of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

Month	Rate in $/kW
October	13.81
November	10.78
December	12.99
January	11.88
February	12.39
March	7.97
April	6.09
May	2.35
June	4.12
July	13.91
August	14.67
September	16.51

(2) Demand Billing Determinant

The Demand Billing Determinant is the highest maximum unanticipated Resource Replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated Resource Replacement load in a month.

N. Unauthorized Increase (UAI) Charge

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

1. Charge for Unauthorized Increase in Energy

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

- 150 mills/kWh; or
- Two times the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the unauthorized increase occurs.

In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, the hourly LAP price for BPA will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from an available energy index in the Pacific Northwest. BPA will provide notice of such a change as soon as practicable.

2. Charge for Unauthorized Increase in Demand

The rate is equal to 1.25 times the applicable monthly demand rate.

For a Load Following product, the UAI demand applies if more than four hours of UAI energy is applied in a month *and* the UAI energy occurred during the hour of the customer's CSP as compared to the customer's CHWM Contract Exhibit A amounts, not including Super Peak amounts in Section 9 of Exhibit A if any, or Exhibit D amounts, whichever is applicable. The UAI demand Billing Determinant will be equal to the amount of UAI energy that was taken during the hour of the customer's CSP.

For all other products and services, such as NR ESS, the UAI demand applies if more than four hours of UAI energy is applied in a month. The UAI demand Billing Determinant will be equal to the customer's single highest hourly UAI energy in that month.

3. UAI Waiver Policy

BPA may, in its sole discretion, waive up to 40 percent of the UAI Energy Charge, 100 percent of the UAI Demand Charge, or a combination of the two, to a Power customer. A Power customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UAI:

(a) was inadvertent or was the result of an equipment failure or outage that the Power customer could not have reasonably foreseen or avoided; and

(b) did not result in harm to BPA's power system or services, or to any other Power customer.

O. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that apply to the following products under the PF-26 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power CRAC also applies to power purchased at the PF Melded rate (PF-26), Industrial Firm Power rate (IP-26), and New Resource Firm Power rate (NR-26).

1. Power CRAC Amount

At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Power CRAC may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power CRAC Amount

The Power CRAC Threshold is an amount of Power RFR below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power CRAC Threshold minus Power RFR.

The Power CRAC Amount is based on the underrun minus the Revenue Financing Amount, limited by the Maximum Power CRAC Recovery Amount (the Power CRAC Cap). There are four possibilities:

(1) If the underrun minus the Revenue Financing Amount is less than $5 million, there is no Power CRAC.

(2) If the underrun minus the Revenue Financing Amount is greater than or equal to $5 million and less than or equal to $100 million, the Power CRAC Amount is equal to the underrun minus the Revenue Financing Amount.

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

(4) If the underrun minus the Revenue Financing Amount is greater than or equal to $500 million, the Power CRAC Amount is equal to $300 million.

The Power CRAC Cap and Thresholds are shown in Table C.1.

Table C.1
Power CRAC Annual Thresholds and Caps
(dollars in millions)

Power RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2025	2026	$0	$37	$300
2026	2027	$0	$37	$300
2027	2028	$0	$37	$300

2. Power CRAC Surcharge Rate

(a) Calculating the Power CRAC Surcharge Rate

The Power CRAC Surcharge rate in mills per kilowatthour will be:

$$\frac{\textit{Power CRAC Amount}}{\sum \textit{BD}}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- Service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads. For FY 2026 PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power CRAC Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power CRAC Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for December through September of the applicable year.

Product Switching Exception: For the PF customers listed in Table C.2, the Power CRAC Surcharge rate in FY 2026 will be applied to the greater of: (i) zero; or (ii) the sum of each customer's HLH and LLH PF System Shaped Load for December 2025 through September 2026 minus the applicable monthly kilowatthour amounts in Table C.2.

A customer's Low Density Discount will be applied to the Power CRAC.

Table C.2
FY 2026 Product Switching Risk Adjustment Amounts

Month	PF Customer Amounts in kWh		
	Clark PUD	***Emerald PUD***	***Snohomish PUD***
December 2025	131,509,383	22,286,413	327,627,286
January 2026	138,752,665	23,513,906	345,672,361
February 2026	110,573,351	18,738,461	275,469,674
March 2026	120,879,379	20,484,985	301,144,922
April 2026	93,682,735	15,876,070	233,390,344
May 2026	121,240,884	20,546,248	302,045,534
June 2026	123,829,730	20,984,971	308,495,085
July 2026	110,219,169	18,678,439	274,587,306
August 2026	113,064,654	19,160,653	281,676,218
September 2026	87,808,257	14,880,544	218,755,348

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power CRAC Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power CRAC Surcharge Rate

An Annual Power CRAC Surcharge rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power CRAC Surcharge rate is calculated by dividing the Power CRAC Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year, in kilowatthours. For FY 2026 the sum of PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025. The Annual Power CRAC Surcharge rate will be:

(1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)

(2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (https://www.bpa.gov/about/finance/quarterly-reports) preliminary, unaudited, year-to-date aggregate financial results for the generation function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (https://www.bpa.gov/about/finance/quarterly-business-review) a preliminary forecast of the Power CRAC Amount.

(b) Notification of Power CRAC

By November 30, 2025, BPA shall complete the calculation of Power RFR as of the end of FY 2025, for use in calculating the Power CRAC applicable to rates for December through September of FY 2026. By November 30, 2026, BPA shall complete the calculation of Power RFR as of the end of FY 2026, for use in calculating the Power CRAC applicable to rates for December through September of FY 2027. By November 30, 2027, BPA shall complete the calculation of Power RDC as of the end of FY 2027, for use in calculating the Power CRAC applicable to rates for December through September of FY 2028.

If the Power CRAC triggers, BPA will notify customers of the preliminary Power CRAC Amount to be recovered by the Power CRAC Surcharge rate for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge.

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power CRAC Amount, the Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power CRAC Amount, Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Power RDC is calculated each fiscal year.

If the Power RDC quantitative criteria (below) are met, the Administrator will calculate the Power RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Power Dividend Distribution (Power DD), distribution to customers, or any other high value Power-specific purposes determined by the Administrator.

A Power DD is a downward adjustment to certain rates that apply to the following products under the PF-26 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power DD also applies to power purchased at the PF Melded rate (PF-26), Industrial Firm Power rate (IP-26), and New Resource Firm Power rate (NR-26).

1. Power RDC Amount

At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) and financial reserves available for risk that are attributed to BPA (BPA RFR) as of the fiscal year preceding the applicable year. If Power RFR is greater than the Power RDC Threshold for that applicable year by at least $5 million, and BPA RFR is greater than the BPA RDC Threshold for that applicable year by at least $5 million, the Administrator will determine a Power RDC Amount. If the Administrator determines that all or part of the Power RDC Amount will be applied to a Power DD, the resulting rate decrease will go into effect beginning the month following the issuance of the Power RDC decision through September 30 of the applicable year.

(a) Calculating the Power RDC Amount

The Power RDC can trigger only if (1) Power RFR exceeds the Power RDC Threshold, and (2) BPA RFR exceeds the BPA RDC Threshold.

For FY 2026, FY2027, and FY 2028, the Administrator shall apply the Power RDC Amount to decrease rates through a Power DD in an amount that is the lesser of 1) the Power RDC Amount, or 2) the Planned Net Revenues for Risk (PNRR) included in rates for the same year in which the RDC is applied. Any remaining Power RDC Amount, if any, will be applied to the purposes listed above. The Power RDC Amount will be the smaller of: Power RFR minus the Power RDC Threshold; or BPA RFR minus the BPA RDC Threshold.

The Thresholds, and PNRR amounts are shown in Table D.1. The BPA RDC Thresholds are shown in Table D.2.

Table D.1
Power RDC Annual Thresholds and Caps
(dollars in millions)

Power RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Power RFR Threshold	Planned Net Revenues for Risk (PNRR)
2025	2026	$746	$0
2026	2027	$746	$0
2027	2028	$746	$0

Table D.2
BPA RDC Annual Thresholds
(dollars in millions)

BPA RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	BPA RFR Threshold
2025	2026	$786
2026	2027	$786
2027	2028	$786

2. Power DD Credit Rate

If the Administrator elects to apply all or a portion of a Power RDC Amount to reduce Power rates, then the following Power DD Credit rate will apply:

(a) Calculating the Power DD Credit Rate

The Power DD Credit rate in mills per kilowatthour will be:

$$\frac{\textit{Power RDC Amount being used for a Power DD}}{\sum BD}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the forecasts for the period following the Administrator's decision through September, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and

- PF System Shaped Loads. For FY 2026 PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power DD Credit rate will be subtracted from the applicable months between the Administrator's decision through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power DD Credit rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load, multiplied by -1, for applicable months between the Administrator's decision through September of the applicable year.

Product Switching Exception: For the PF customers listed in Table C.2 in GRSP II.O.2(b) above, the Power DD Credit rate in FY 2026 will be applied to -1 multiplied by the greater of: (i) zero; or (ii) the sum of each customer's HLH and LLH PF System Shaped Load for the applicable months through September 2026 minus the applicable monthly kilowatthour amounts in Table C.2 above.

A customer's Low Density Discount will be applied to the Power DD, which will be a charge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power DD Credit rate will be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for applicable months between the Administrator's decision through September of the applicable year.

(d) Annual Power DD Credit Rate

An Annual Power DD Credit rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power DD Credit rate is calculated by dividing the Power RDC Amount being used for a Power DD by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year, in kilowatthours. For FY 2026 the sum of PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025. The Annual Power DD Credit rate will be:

(1) Added to the Load Shaping Charge True-Up rate (GRSP II.E, Section 1); and

(2) Added to the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power RDC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function. For the Second and Third Quarter Reviews, BPA will post to its external website (www.bpa.gov) a preliminary forecast of the Power RDC Amount.

(b) Notification of Power RDC

By November 30, 2025, BPA shall complete the calculation of Power RFR as of the end of FY 2025, for use in calculating the Power RDC applicable to rates for FY 2026. By November 30, 2026, BPA shall complete the calculation of Power RFR as of the end of FY 2026, for use in calculating the Power RDC applicable to rates for FY 2027. By November 30, 2027, BPA shall complete the calculation of Power RFR as of the end of FY 2027, for use in calculating the Power RDC applicable to rates for FY 2028.

If the Power RDC triggers, BPA will notify customers of the preliminary Power RDC Amount and how such amount will be used. Such notice shall be issued as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power RDC Amount.

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power RDC Amount, and if applicable, the Power DD Credit rate and Annual Power DD Credit rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power RDC Amount by December 15 of each applicable year, unless extended by BPA. If BPA extends the timeframe for issuing the final Power RDC Amount, BPA shall identify the new date for issuing such decision in a public notice. Such date shall be no later than February 1 of the following year.

Q. Power Financial Reserves Policy Surcharge (Power FRP Surcharge)

The Power FRP Surcharge is an upward adjustment to certain rates that apply to the following products under the PF-26 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power FRP Surcharge also applies to power purchased at the PF Melded rate (PF-26), Industrial Firm Power rate (IP-26), and New Resource Firm Power rate (NR-26).

1. Power FRP Surcharge Amount

At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Power FRP Surcharge may trigger, resulting in a rate increase that will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power FRP Surcharge Amount

The Power FRP Surcharge Threshold is an amount of Power RFR, below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power FRP Surcharge Threshold minus Power RFR.

The Power FRP Surcharge Amount is based on the underrun minus the Revenue Financing Amount, limited by the Base Surcharge. There are three possibilities:

(1) If the underrun minus the Revenue Financing Amount is less than $5 million, there is no Power FRP Surcharge.

(2) If the underrun minus the Revenue Financing Amount is greater than or equal to $5 million and less than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the underrun minus the Revenue Financing Amount.

(3) If the underrun minus the Revenue Financing Amount is greater than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the Base Surcharge.

The Power FRP Surcharge Thresholds and Base Surcharges are shown in Table E.

Table E
Power FRP Surcharge Annual Thresholds and Caps
(dollars in millions)

Power RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Base Surcharge
2025	2026	$373	$37	$40
2026	2027	$373	$37	$40
2027	2028	$373	$37	$40

2. Power FRP Surcharge Rate

(a) Calculating the Power FRP Surcharge Rate

The Power FRP Surcharge rate in mills per kilowatthour will be:

$$\frac{\textit{Power FRP Surcharge Amount}}{\sum BD}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads. For FY 2026 PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power FRP Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power FRP Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for December through September of the applicable year.

Product Switching Exception: For the PF customers listed in Table C.2 in GRSP II.O.2(b) above, the Power FRP Surcharge rate in FY 2026 will be applied to the greater of: (i) zero; or (ii) the sum of each customer's HLH and LLH PF System Shaped Load for December 2025 through September 2026 minus the applicable monthly kilowatthour amounts in Table C.2 above.

A customer's Low Density Discount will be applied to the Power FRP Surcharge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power FRP Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power FRP Surcharge Rate

An Annual Power FRP Surcharge rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Power FRP Surcharge rate is calculated by dividing the Power FRP Surcharge Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year, in kilowatthours. For FY 2026 the sum of PF System Shaped Loads will not include that portion of PF System Shaped Load that has been converted from a Slice percentage to a non-Slice TOCA beginning October 1, 2025. The Annual Power FRP Surcharge rate will be:

(1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)

(2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power FRP Surcharge Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

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

For the second and third quarter reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power FRP Surcharge Amount.

(b) Notification of Power FRP Surcharge

By November 30, 2025, BPA shall complete the calculation of Power RFR as of the end of FY 2025, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2026. By November 30, 2026, BPA shall complete the calculation of Power RFR as of the end of FY 2026, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2027. By November 30, 2027, BPA shall complete the calculation of Power RFR as of the end of FY 2027, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2028.

If the Power FRP Surcharge triggers, BPA will notify customers of the preliminary Power FRP Surcharge Amount to be recovered by the Power FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge.

BPA will hold at least one public meeting to discuss the calculations of Power RFR, the Power FRP Surcharge Amount, the Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power FRP Surcharge Amount, Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

R. Slice True-Up Adjustment

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

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

(a) Calculation of the Slice True-Up Adjustment Charge for the Composite Cost Pool

Following the end of each fiscal year of the rate period, BPA shall:

(1) subtract:

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

from

the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;

(2) divide the difference determined in (1) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM Section 5.1.1 and the Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1 for Load Following customers; and

(3) multiply the dollar amount in (2) above by each Slice customer's Slice percentage for the applicable fiscal year.

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

The Composite Cost Pool True-Up Table (Table F) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. Included in these adjustments and credits are the actual Firm Surplus and Secondary Adjustment from Unused RHWM and the actual DSI Revenue Credit described in (b) and (c) below.

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

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

(1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-26 7(i) process; and

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

Where:

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

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

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

(3) the sum of forecast TOCAs is the sum of TOCAs used to set the PF-26 Composite Customer rate; and

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

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) **×** 47.14 mills/kWh.

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

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

(c) Calculation of the Actual DSI Revenue Credit

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

(1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-26 7(i) process;

(2) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* (ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by – 7.51 mills/kWh; and

(3) DSI Take-or-Pay revenues

Where:

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

–7.51 mills/kWh is calculated by the equation:

PFMEES – 8.92 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of 1.41 mills/kWh and is subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q).

See Appendix A, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

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

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

Following the end of each fiscal year and pursuant to TRM Section 2.7.2, BPA shall:

(a) Subtract:

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

from

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

and

(b) for each Slice customer, multiply the resulting difference from (a) above by the ratio of (i) the customer's Slice percentage for the fiscal year in Exhibit K of the Slice/Block Contract to (ii) the sum of all customers' Slice percentages for the fiscal year in all Exhibits K of the Slice/Block CHWM Contracts.

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

Table F
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2026 forecast ($000)	FY 2027 forecast ($000)	FY 2028 forecast ($000)
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		348,985	413,666	380,974
5	BUREAU OF RECLAMATION		195,235	206,763	208,089
6	CORPS OF ENGINEERS		292,351	316,276	341,040
7	CRFM STUDIES		12,510	12,914	13,329
8	LONG-TERM CONTRACT GENERATING PROJECTS		30,482	35,637	32,550
9	**Sub-Total**		**879,563**	**985,256**	**975,981**
10	**Operating Generation Settlement Payment and Other Payments**				
11	COLVILLE GENERATION SETTLEMENT		27,523	28,132	28,760
12	SPOKANE LEGISLATION PAYMENT		6,881	7,033	7,190
13	AMORTIZATION OF P2IP SETTLEMENT PAYMENTS		14,222	14,222	14,222
14	AMORTIZATION OF 6S SETTLEMENT PAYMENTS		13,900	13,900	13,900
15	**Sub-Total**		**62,526**	**63,287**	**64,072**
16	**Non-Operating Generation**				
17	TROJAN DECOMMISSIONING		1,300	1,329	1,359
18	WNP-1&3 DECOMMISSIONING		1,400	1,431	1,463
19	**Sub-Total**		**2,700**	**2,760**	**2,822**
20	**Gross Contracted Power Purchases**				
21	PNCA HEADWATER BENEFITS		-	-	-
22	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		-	-	-
23	**Sub-Total**		**-**	**-**	**-**
24	**Bookout Adjustment to Power Purchases (omit)**				
25	**Augmentation Power Purchases (omit - calculated below)**				
26	AUGMENTATION POWER PURCHASES		-	-	-
27	**Sub-Total**		**-**	**-**	**-**
28	**Exchanges and Settlements**				
29	RESIDENTIAL EXCHANGE PROGRAM (REP)		286,516	286,530	287,331
30	OTHER SETTLEMENTS		-	-	-
31	**Sub-Total**		**286,516**	**286,530**	**287,331**
32	**Renewable Generation**				
33	RENEWABLES (excludes KIII)		15,308	3,483	2,212
34	**Sub-Total**		**15,308**	**3,483**	**2,212**
35	**Generation Conservation**				
36	CONSERVATION ACQUISITION (Purchases)		65,385	65,385	86,513
37	CONSERVATION INFRASCTRUCTURE		32,443	32,492	32,497
38	LOW INCOME WEATHERIZATION & TRIBAL		6,005	6,005	6,005
39	ENERGY EFFICIENCY DEVELOPMENT		-	-	-
40	DISTRIBUTED ENERGY RESOURCES		500	500	500
41	LEGACY		-	-	-
42	MARKET TRANSFORMATION		15,000	15,000	15,000
43	**Sub-Total**		**119,333**	**119,382**	**140,515**
44	**Power System Generation Sub-Total**		**1,365,945**	**1,460,699**	**1,472,933**
45	**Power Non-Generation Operations**				
46	**Power Services System Operations**				
47	EFFICIENCIES PROGRAM		-	-	-
48	INFORMATION TECHNOLOGY		-	-	-
49	GENERATION PROJECT COORDINATION		4,501	4,615	4,732
50	SLICE IMPLEMENTATION		835	863	891
51	**Sub-Total**		**5,336**	**5,478**	**5,623**
52	**Power Services Scheduling**				
53	OPERATIONS SCHEDULING		12,028	12,516	13,038
54	OPERATIONS PLANNING		11,861	12,170	12,499
55	**Sub-Total**		**23,889**	**24,686**	**25,537**

Table F, continued
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2026 forecast ($000)	FY 2027 forecast ($000)	FY 2028 forecast ($000)
56	**Power Services Marketing and Business Support**				
57	GRID MOD		324	351	
58	EIM INTERNAL SUPPORT		-	-	
59	POWER INTERNAL SUPPORT		23,020	23,701	24,425
60	POWER R&D		2,156	2,156	2,156
61	SALES & SUPPORT		14,504	15,022	15,567
62	STRATEGY, FINANCE & RISK MGMT		4,385	6,496	6,364
63	EXECUTIVE AND ADMINISTRATIVE SERVICES		-	-	-
64	CONSERVATION SUPPORT		9,555	9,869	10,189
65	**Sub-Total**		**53,943**	**57,595**	**58,701**
66	**Power Non-Generation Operations Sub-Total**		**83,167**	**87,759**	**89,862**
67	**Power Services Transmission Acquisition and Ancillary Services**				
68	TRANSMISSION and ANCILLARY Services - System Obligations		2,408	2,412	2,741
69	3RD PARTY GTA WHEELING		92,598	94,644	96,736
70	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)		3,300	3,300	3,300
71	TRANS ACQ GENERATION INTEGRATION		24,253	24,415	25,543
72	TELEMETERING/EQUIP REPLACEMT		-	-	-
73	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**122,559**	**124,771**	**128,320**
74	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**				
75	**Fish & Wildlife**		275,484	282,484	289,505
76	**USF&W Lower Snake Hatcheries**		33,777	34,707	35,669
77	**Planning Council**		12,041	11,876	12,052
78	**Long Term Funding Agreements**		18,116	18,075	19,063
79	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**339,418**	**347,141**	**356,288**
80	**BPA Internal Support**				
81	**Additional Post-Retirement Contribution**		16,442	17,182	17,927
82	**Agency Services G&A (excludes direct project support)**		141,885	152,698	158,623
83	**BPA Internal Support Sub-Total**		**158,328**	**169,880**	**176,550**
84	**Bad Debt Expense**		-	-	-
85	**Other Income, Expenses, Adjustments**		-	-	-
86	**Depreciation**		148,080	151,705	155,344
87	**Amortization**		335,151	360,724	387,769
88	**Accretion**		42,607	44,438	46,350
89	**Total Operating Expenses**		**2,595,255**	**2,747,118**	**2,813,416**
90	**Other Expenses**				
91	Net Interest Expense		183,019	181,374	179,992
92	LDD		42,805	43,959	44,496
93	Irrigation Rate Discount Costs		22,504	22,504	22,504
94	**Sub-Total**		**248,328**	**247,837**	**246,992**
95	**Total Expenses**		**2,843,583**	**2,994,955**	**3,060,408**

Table F, continued
Composite Cost Pool True-Up Table

		Actual Data ($000)	FY 2026 forecast ($000)	FY 2027 forecast ($000)	FY 2028 forecast ($000)
96	**Revenue Credits**				
97	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		141,531	141,531	141,531
98	Downstream Benefits and Pumping Power revenues		21,193	21,193	21,193
99	4(h)(10)(c) credit		124,911	131,117	132,163
100	PRSC Net Credit (Composite)		-	-	-
101	Colville and Spokane Settlements		4,600	4,600	4,600
102	Energy Efficiency Revenues		-	-	-
103	FPS Real Power Losses		44,921	44,921	44,921
104	Miscellaneous revenues		9,351	9,551	9,819
105	Renewable Energy Certificates		-	-	-
106	Net Revenues from other Designated BPA System Obligations (Upper Baker)		485	476	456
107	RSS Revenues		3,141	3,186	3,227
108	Firm Surplus and Secondary Adjustment (from Unused RHWM)		90,764	73,915	59,710
109	Balancing Augmentation Adjustment		834	3,378	685
110	Transmission Loss Adjustment		41,097	41,396	41,574
111	Tier 2 Rate Adjustment		8,243	9,667	10,488
112	NR Revenues		7,433	19,855	27,985
113	**Total Revenue Credits**		**498,503**	**504,785**	**498,353**
114					
115	**Augmentation Costs (not subject to True-Up)**				
116	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		11,267	11,392	2,463
117	Augmentation Purchases (including Other Augmentation)		10,808	17,045	21,198
118	**Total Augmentation Costs**		**22,075**	**28,437**	**23,661**
119					
120	**DSI Revenue Credit**				
121	Revenues 11aMW @ IP rate		4,469	4,469	4,481
122	**Total DSI revenues**		**4,469**	**4,469**	**4,481**
123					
124	**Minimum Required Net Revenue Calculation**				
125	Principal Payment of Fed Debt for Power		437,874	441,000	586,417
126	Repayment of Non-Federal Obligations (EN Line of Credit)		-	-	-
127	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)		36,161	39,551	35,031
128	Irrigation assistance		20,662	6,370	11,634
129	**Sub-Total**		**494,697**	**486,921**	**633,082**
130	Depreciation		148,080	151,705	155,344
131	Amortization		335,151	360,724	387,769
132	Accretion		42,607	44,438	46,350
133	Capitalization Adjustment		(45,937)	(45,937)	(45,937)
134	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)		(42,053)	(44,109)	(45,757)
135	Amortization of Cost of Issuance (MRNR-reverse sign)		208	308	408
136	Gains/Losses on Extinguishment		-	-	-
137	Cash freed up by DSR refinancing		(21,200)	(21,687)	(22,158)
138	Non-Cash Expenses		-	-	-
139	Prepay Revenue Credits		(30,600)	(30,600)	(30,600)
140	Non-Federal Interest (Prepay)		3,329	2,064	740
141	Contribution to decommissioning trust fund		(15,700)	(16,300)	(17,000)
142	Gains/losses on decommissioning trust fund		(16,849)	(17,824)	(18,855)
143	Interest earned on decommissioning trust fund		-	-	-
144	Revenue Financing Requirement		(39,000)	(43,000)	(44,000)
145	**Sub-Total**		**318,036**	**339,782**	**366,303**
146	Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses		176,662	147,139	266,779
147	Minimum Required Net Revenues		**176,662**	**147,139**	**266,779**
148					
149	Annual Composite Cost Pool (Amounts for each FY)		**2,539,348**	**2,661,277**	**2,848,014**
150					
151	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**				
152	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)				
153	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)				
154	TRUE-UP ADJUSTMENT CHARGE BILLED (19.74071percent)				

Table G
Slice Cost Pool True-Up Table

		Audited Actual Data ($000)	FY 2026 forecast ($000)		FY 2027 forecast ($000)		FY 2028 forecast ($000)
1	**Slice Expenses**						
2							
3							
4	**Total Slice Expenses**		$ -		$ -		$ -
5							
6	**Slice Credits**						
7							
8	**Total Slice Credits**		$ -		$ -		$ -
9							
10	Annual Slice Cost Pool (Amounts for each FY)		$ -		$ -		$ -
11							
12	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL**						
13	TRUE UP AMOUNT (Diff. between actual Slice Cost Pool and forecast Slice COST Pool for applicable FY)						
14							
15	TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)						

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are shown in Table H below. These loads are applicable to each year of the rate period, FY 2026, FY 2027 and FY2028, and are established pursuant to Section 2 of the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement).

Table H
Residential Load for the BP-26 Rate Period (in kWh)

Month	Avista	Idaho	NorthWestern
October	248,113,363	471,434,012	48,231,893
November	330,333,510	461,384,863	57,801,819
December	415,844,668	594,172,856	71,620,804
January	508,088,930	691,937,925	86,421,341
February	424,264,106	649,447,117	80,456,449
March	420,669,441	604,544,866	74,577,573
April	326,210,755	513,823,955	63,357,610
May	283,012,920	516,546,640	54,465330
June	267,953,426	589,073,840	53,041,326
July	324,026,031	746,777,237	57,312,319
August	357,356,755	848,392,490	65,960,034
September	295,491,533	678,433,870	58,706,804

Month	PacifiCorp	Portland General	Puget Sound
October	575,612,538	530,681,297	783,254,481
November	732,160,535	628,736,491	1,018,127,415
December	928,002,233	817,298,816	1,309,072,447
January	1,052,986,956	963,596,984	1,423,090,884
February	928,062,707	841,921,891	1,303,027,800
March	875,551,639	798,645,630	1,286,356,586
April	724,735,330	688,578,711	1,120,194,835
May	619,916,767	596,376,364	928,665,086
June	650,450,123	591,497,999	826,873,652
July	787,430,724	687,649,182	841,809,009
August	842,495,192	747,700,565	879,307,808
September	687,932,667	678,724,937	837,374,625

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

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-26 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3)

Surcharge is displayed in the table in Section 6.1 of the PF-26 rate schedule and is subject to modification under this GRSP.

In implementing the REP, BPA has identified circumstances where a utility's ASC may be modified during the BPA rate period (*e.g.*, new resource additions, new NLSLs, changes in service territory). Subject to limitations in the 2008 ASC Methodology, when BPA modifies a utility's ASC during a BPA rate period, the modified ASC will be effective on the date specified in BPA's notice to the participating utility confirming the modification of its ASC. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in Section 6.1 of the PF-26 rate schedule, BPA shall adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges will be accomplished by substituting all modified ASCs and recomputing the rates in Section 6.1 of the PF-26 rate schedule. This recomputation will be accomplished by:

1. Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to $/MWh).

2. Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-26 7(i) proceeding.

3. Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.

4. Summing the unconstrained benefits for each participant to compute total unconstrained benefits.

5. Computing the difference between the total unconstrained benefits and $859,440,527 (the total REP benefits adopted for the three-year rate period in the BP-26 7(i) proceeding).

6. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.

7. Dividing the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and adding each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Tables 2.4.11 and 2.4.12 of the Power Rates Study Documentation, BP-26-E-BPA-01A. Table 2.4.11 will be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges will take effect on the day that the utility's modified ASC takes effect. This adjustment will occur as frequently as ASCs are modified during the two-year rate period the PF Exchange rate herein is in effect.

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

U. Conservation Surcharge

The Conservation Surcharge, if implemented, will be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-26 (including Slice purchasers), NR-26, and IP-26 rate schedules.

V. [Reserved for Future Use]

W. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a customer that makes a contractual commitment to purchase under this option. The rates and Billing Determinants under this option will be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible PF rate option will purchase the same set of power products and services that it would otherwise purchase under the PF-26 rate schedule. The flexible rates and Billing Determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4, and 5 of the PF-26 rate schedule been applied to the same sales.
- The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in Sections 2, 3, 4, and 5 of the PF-26 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-26 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate program by purchasing under the Flexible PF Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

X. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a customer purchasing Firm Requirements Power charged under Section 2.1 of the PF-26 rate schedule may agree to a PF-26 Tier 1 Customer Charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-26 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to "shape" certain PF-26 Tier 1 Customer Charges within the fiscal year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-26 Tier 1 Customer rates will be mutually agreed to by BPA and the customer. Requests to shape Customer Charges during the rate period must be received by BPA no later than September 1, 2025.

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

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

- Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping.
- No Material Adverse Impacts on BPA's Cash Flow: The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. To accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

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

The Flexible NR rate option will be offered at BPA's discretion to a customer that makes a contractual commitment to purchase under this option. The rates and Billing Determinants under this option will be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible NR rate option will purchase the same set of power products and services that it would otherwise purchase under the NR-26 rate schedule. The flexible rates and Billing Determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4 and 5 of the NR-26 rate schedule been applied to the same sales.
- The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the

contractual limit will be billed at the rates specified in Sections 2, 3, 4 and 5 of the NR-26 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-26 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible NR Rate program by purchasing under the Flexible NR Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

Z. Cost Contributions

Pursuant to Section 7(j) of the Northwest Power Act (16 U.S.C. § 839e(j)), BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is shown in Table I.

Table I
Resource Cost Contribution

Rate Schedule	Federal Base System	Exchange Resources	New Resources
PF	42.63%	56.74%	.63%
IP	0.00%	0.00%	100.00%
NR	0.00%	0.00%	100.00%
FPS	0.00%	0.00%	100.00%

2. The cost of resources acquired to meet load growth within the region is estimated to be 56.43 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 68.93 mills/kWh.

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

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

Table J
PF Tier 1 Equivalent Rates

Month	Energy Rate in mills/kWh		Demand Rate in $/kW
	HLH	*LLH*	*HLH*
October	46.75	44.97	13.81
November	35.65	37.76	10.78
December	43.75	44.91	12.99
January	39.68	39.92	11.88
February	41.55	45.30	12.39
March	25.31	30.66	7.97
April	18.45	23.21	6.09
May	4.72	8.85	2.35
June	11.22	12.20	4.12
July	47.10	44.18	13.91
August	49.92	46.44	14.67
September	56.63	55.18	16.51

These rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). *See* Appendix A, Supplemental Information, for adjusted PF Tier 1 Equivalent rates.

AB. Washington Cap-and-Invest Program Charge

This charge will be applicable if BPA becomes the First Jurisdictional Deliverer in the Washington Cap-and-Invest Program.

The Washington Cap-and-Invest Program Charge shall apply to any customer that:

1. is subject to the Washington Cap-and-Invest Program;

2. is purchasing federal power from BPA under the PF, NR, or FPS rates; and

3. either (a) fails to register with the Washington (WA) Department of Ecology and therefore does not receive an allocation of no-cost allowances, or (b) registers with WA Department of Ecology, but does not sign a BPA power sales contract revision agreeing to transfer their allocation of no-cost allowances for the federal system to BPA.

A customer that meets the requirements of 1-3 will be charged the Washington Cap-and-Invest Program Charge, which will be determined pursuant to the following formula:

Sales	X	Federal system emissions factor	X	Unit cost of allowances	X	1.25

Where:
Sales = For the Calendar Year (CY), the total of sales to a customer, in megawatthours, of: Firm Requirements Power at the PF rate; power for New Large Single Loads at the NR rate; and power under the FPS Rate schedule, Section 10.

Federal system emissions factor = Asset Controlling Supplier (ACS) emissions factor published by WA Department of Ecology for the CY, in metric tons of carbon dioxide equivalency per megawatthour (MT CO_2e/MWh).

Unit cost of allowances = Auction settlement price or secondary market price for allowances (one allowance covers the compliance obligation for 1 MT CO_2e), in dollars per megawatthour. Unit cost will reflect actual cost by BPA of procuring the allowances needed to cover the compliance obligation. BPA will procure the allowances at its discretion at a Program auction or in the secondary market.

The Washington Cap-and-Invest Program Charge will be included on bills for December for the compliance obligation incurred for power sales for the previous calendar year.

AC. Resource Adequacy Service

This service will only be applicable if BPA begins participation in the Western Resource Adequacy Program (WRAP) 3B Binding Program.

1. Credit for Above-RHWM Load

A Load Following customer with non-federal resources serving Above-RHWM Load will be eligible to receive a monthly credit in any period in which BPA is a binding WRAP participant, if the customer meets the WRAP forward-showing qualifying capacity capability (QCC) requirement for such non-federal resources that they have the rights to us to serve load during that binding season. The customer must submit WRAP registered with QCC resource information to BPA by the above identified Forward Showing customer data submittal dates (January 31 and August 31 respectively).

(a) Rate

FY 2026, FY 2027 and FY 2028 monthly rate is -4.53 mills/kWh.

(b) Billing Determinant

The qualifying non-federal resource amounts (in kilowatthours) identified in Exhibit D of the customer's CHWM contract.

2. Charge for New Large Single Loads

A Load Following customer with a New Large Single Load (NLSL) will be subject to a monthly charge in any period in which BPA is a binding WRAP participant if the customer does not submit to BPA, by the above identified Forward Showing customer data submittal dates (January 31 and August 31 respectively), either: (a) an approved exclusion attestation for the NLSL in accordance with the WRAP and approved by BPA; or (b) WRAP registered QCC resource information for all non-federal resources serving the NLSL.

(a) Rate

FY 2026, FY 2027 and FY 2028 monthly rate is 4.53 mills/kWh.

(b) Billing Determinant

The qualifying forecast NLSL amounts (in kilowatthours) identified in Exhibit D of the customer's CHWM contract.

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SECTION III. DEFINITIONS

A. Power Products and Services offered by BPA Power Services

1. Block Product

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

2. Capacity Without Energy

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

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

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility will be made available to eligible customers under the Priority Firm Power (PF-26), New Resources Firm Power (NR-26), and Firm Power and Surplus Products and Services (FPS-26) rate schedules. Such power is not available under the PF Exchange rate.

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

(a) Power sold for construction is to be used in the construction of the project.
(b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.
(c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.
(d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. Energy Shaping Service for NLSL

Energy Shaping Service is an optional service for Load Following customers serving a New Large Single Load (NLSL) with a non-federal resource. ESS includes a capacity component and an energy component. These services shape a customer's resource energy and capacity output amounts to the actual load of a NLSL.

5. Firm Requirements Power

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

6. Forced Outage Reserve Service (FORS)

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

7. Industrial Firm Power (IP)

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

8. Load Following Product

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

9. Load Shaping

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

10. New Resource Firm Power (NR)

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

(a) for any NLSL, as defined in the Northwest Power Act;
(b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

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

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

11. NR Resource Flattening Service (NRFS)

NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

12. Priority Firm Power (PF)

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

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

13. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a customer pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible Pacific Northwest utilities at a utility's Average System Cost (ASC). 16 U.S.C. § 839c(c). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities (PF Exchange rate). The amounts of power purchased and sold are both equal to the utility's eligible residential and farm load. Benefits must be passed directly to the utility's residential and farm customers.

14. Resource Remarketing Service (RRS)

Resource Remarketing Service (RRS) is a service that BPA makes available at its discretion to Load Following customers where BPA remarkets non-federal resources on behalf of customers and provides them with remarketing credits, net of a remarketing fee.

15. Resource Support Services (RSS)

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

16. Secondary Crediting Service (SCS)

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

Under SCS Option 2, the customer applies its resource directly to load, and federal deliveries cover the net load.

17. Slice/Block Product

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

18. Transfer Service

As defined in the CHWM Contracts, Transfer Service means the transmission, distribution and other services provided by a third party transmission provider to deliver electric energy and capacity over its transmission system.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the customer's Rate Period High Water Mark, as determined in the RHWM Process.

2. Actual Monthly/Diurnal Tier 1 Load

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

3. Billing Determinant

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

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

4. Charge

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

5. Contract Demand

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

6. Contract Demand Quantity (CDQ)

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

7. Contract Energy

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

8. Contract High Water Mark (CHWM)

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

9. CHWM Contract

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

10. Customer

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

11. DSI Reserve

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

12. Energy Efficiency Incentive

The Energy Efficiency Incentive is a funding mechanism that establishes a budget from which BPA funds energy efficiency incentive payments and associated qualified performance payments for customers with a CHWM Contract.

13. Flat Annual Shape

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

14. Heavy Load Hours (HLH)

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

15. Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index

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

16. Load Aggregation Point (LAP)

The LAP is a set of pricing nodes that is used for the submission of bids and settlement of demand in the Energy Imbalance Market (EIM).

17. Light Load Hours (LLH)

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

18. Metered Demand

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

(a) at each point of delivery for which the Metered Demand is the basis for determination of the measured demand;
(b) during each time period specified in the applicable rate schedule; and
(c) during any billing period.

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

19. Metered Energy

The Metered Energy for a customer will be the number of kilowatthours recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a customer:

(a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and
(b) during any billing period.

20. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer. (As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.)

21. NR Hourly Load

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

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or federal agency eligible to purchase requirements power from BPA pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b).

23. Rate Period High Water Mark (RHWM)

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

24. Remarketing Value

The Remarketing Value is used to price any unpurchased market purchases associated with all forms of augmentation including Tier 1, Tier 2, and Other Augmentation in addition to valuing all forms of remarketing (Tier 2, non-federal and Resource Remarketing Service).

25. Resource Shaping Charge

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

26. Resource Shaping Rate

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

27. Retail Access

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

28. RHWM Tier 1 System Capability (RT1SC)

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

29. Super Peak Credit

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

30. Super Peak Period

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

The Super Peak Period hours for FY 2026-2028 are as follows (HE = Hour Ending):

October – May	HE 7 through HE 9 and HE 18 through HE 20
June – September	HE 15 through HE 20

31. System Shaped Load

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

32. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the Billing Determinant for the customer charges for each customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM Section 5.1.1. TOCAs are posted on BPA's website.

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

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

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

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

35. Total Retail Load (TRL)

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

36. Unanticipated Load

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

37. Wheel Turning Load

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

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APPENDIX

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Power Rates Schedules and GSRPs
Appendix A: Supplemental Information

Any adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q) will be summarized here. Any other adjustments to rates or GRSPs during the Rate Period, made in accordance with these rate schedules and GRSPs, will also be summarized here.

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BONNEVILLE POWER ADMINISTRATION
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