

BP-27 Rate Proceeding

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

BP-27-E-BPA-02

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BONNEVILLE POWER ADMINISTRATION

REVISED 2026 POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

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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
<u>COORA</u>	<u>Court-Ordered Operation Rate Adder</u>
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	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
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

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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		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Customer Rate	2,141,296	(366,092)	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		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
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:

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

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 percent, 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:

$$\textit{Tier 1 CSP} - \textit{aHLH} - \textit{CDQ} - \textit{SuperPeak}$$

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	
	<i>HLH</i>	<i>LLH</i>
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 = RHWMTier 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 1.

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	
	<i>HLH</i>	<i>LLH</i>
October	48.57	46.79
November	37.47	39.58
December	45.57	46.73
January	41.49	41.74
February	43.37	47.12
March	27.12	32.48
April	20.27	25.03
May	6.53	10.67
June	13.04	14.02
July	48.91	46.00
August	51.73	48.26
September	58.45	57.00

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), and the Court-Ordered Operation Rate Adder (GRSP II.AD). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in Appendix 1.

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		
	<i>Base PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Avista	58.93	6.16	65.09
Idaho Power	58.93	1.14	60.07
NorthWestern	58.93	22.48	81.40
PacifiCorp	58.93	33.14	92.07
Portland General	58.93	25.76	84.68
Puget Sound Energy	58.93	17.17	76.10
Consumer-Owned Utilities	<i>Base Tier 1 PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Snohomish County PUD No 1	58.12	0.86	58.97

6.2 Energy Billing Determinant

The Energy 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, & Special Rate Provisions	Applicable to:			
		Firm Requirements			REP
	Load Following	Block only & Block Portion of Slice/Block	Slice Portion of Slice/Block		
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	

GRSP II.	Adjustments, Charges, & Special Rate Provisions	Applicable to:			
		Firm Requirements			REP
	Load Following	Block only & Block Portion of Slice/Block	Slice Portion of Slice/Block		
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		
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			
AD	Court-Ordered Operation Rate Adder (COORA)	X	X		

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

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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	
	<i>HLH</i>	<i>LLH</i>
October	122.21	120.43
November	111.11	113.22
December	119.21	120.37
January	115.14	115.38
February	117.01	120.76
March	100.77	106.12
April	93.91	98.67
May	80.18	84.31
June	86.68	87.66
July	122.56	119.64
August	125.38	121.90
September	132.09	130.64

2.1.1.1 REP Surcharge

Each Energy Rate in the table above reflects an REP Surcharge of 7.98 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), and the Court-Ordered Operation Rate Adder (GRSP II.AD). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix 1.

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
<u>AD</u>	<u>Court-Ordered Operation Rate Adder (COORA)</u>

Appendix	Adjustments and Charges
A	Supplemental Information

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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	
	<i>HLH</i>	<i>LLH</i>
October	56.84	55.06
November	45.74	47.85
December	53.84	55.00
January	49.76	50.01
February	51.64	55.39
March	35.39	40.75
April	28.54	33.30
May	14.80	18.94
June	21.31	22.29
July	57.18	54.27
August	60.00	56.53
September	66.72	65.27

2.1.1.1 REP Surcharge

Each Energy Rate in the table above reflects an REP Surcharge of 7.98 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each Energy Rate in the table above reflects a 0.675 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), and the Court-Ordered Operation Rate Adder (GRSP II.AD). Any adjustments to rates and GRSPs during the Rate Period due to such Risk Adjustments are summarized in Appendix 1.

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 1.

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
<u>AD</u>	<u>Court-Ordered Operation Rate Adder (COORA)</u>

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: i) firm energy with negotiated curtailment rights; ii) resource support and scheduling services for non-federal resources not eligible for services under Section 7 of this FPS Rate Schedule; iii) 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 iv) 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 14.67 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

GENERAL RATE SCHEDULE PROVISIONS

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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: i) 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 ii) 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.

Customer Arrangements Directly with the Third-Party Transmission Provider

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. RHWMTier 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 RHWMT 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 RHWMTier 1 System
Capability

Month	RT1SC in kWh	
	<i>HLH</i>	<i>LLH</i>
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); and the Court-Ordered Operation Rate Adder (GRSP II.AD).** 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%	$31.5 < X \leq 35.0$	$10.8 < X \leq 12.0$
1.0%	$28.0 < X \leq 31.5$	$9.6 < X \leq 10.8$
1.5%	$24.5 < X \leq 28.0$	$8.4 < X \leq 9.6$
2.0%	$21.0 < X \leq 24.5$	$7.2 < X \leq 8.4$
2.5%	$17.5 < X \leq 21.0$	$6.0 < X \leq 7.2$
3.0%	$14.0 < X \leq 17.5$	$4.8 < X \leq 6.0$
3.5%	$10.5 < X \leq 14.0$	$3.6 < X \leq 4.8$
4.0%	$7.0 < X \leq 10.5$	$2.4 < X \leq 3.6$
4.5%	$3.5 < X \leq 7.0$	$1.2 < X \leq 2.4$
5.0%	$X \leq 3.5$	$X \leq 1.2$

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 11.71 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 RHWMTier 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	4.59
2027	4.59
2028	4.59

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); and the Court-Ordered Operation Rate Adder (GRSP II.AD). See Appendix 1, 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.

$$\text{Annual Deviation} = \frac{\text{Actual Annual Tier 1 Load (measured)}}{\text{TOCA Load (calculated)}}$$

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).

$$\text{Above-Forecast Amount} = \frac{\text{RHWM (calculated)}}{\text{minus TOCA Load (calculated)}}$$

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.

$$\frac{\text{True-Up Charge}}{\text{Billing Determinant}} = \frac{\text{Absolute value of the Annual Deviation}}{\text{minus Above-RHWM Load}}$$

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:

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

If the resulting TOCA differs from the TOCA calculated in the BP-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 i) acquiring annexed load from a utility with a CHWM, or ii) 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 i) acquiring annexed load from a utility with a CHWM, or ii) having its load annexed by a utility with a CHWM, then the customer's RHW 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 \$4.93 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 i) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); ii) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.2(2) of Exhibit D (Exhibit D planned amounts); or iii) 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: i) the annual average Exhibit A amount converted to a monthly/diurnal shape (in megawatthours) using the corresponding monthly/diurnal hours for the same year; minus ii) 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 (UAI) 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 i) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and ii) 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 megawatt-hour 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 (i) the annual Exhibit A amounts in kilowatthours plus (ii) 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 Customer's NLSL(s) (billed as either individual NLSLs or as an aggregate NLSL) as determined by the Customer's contract.

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 percent. A customer may initially elect a higher level of service (3, 4 or 5 percent level of service) by providing written notice to BPA no later than February 1, 2025. Customer may change the default or initially elected level of service applicable to the customer ("Level of Service %") prior to a fiscal year pursuant to the terms of the customer's contract. 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 kW

$LevelofService\%$ = 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 percent plus 4 percent multiplied by the $MonthlyPeak$. The Actual Capacity Used in an hour is equal to the measured 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) will apply in any hour where the Actual Capacity Used, rounded down to a whole megawatthour, exceeds the monthly amount of capacity purchased from BPA.

(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 megawatthours for each hour to each NLSL, or aggregation of NLSLs served by a single Load Following customer, seven (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 megawatthours for each hour for each NLSL, or aggregation of NLSLs served by a single Load Following customer, seven (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 NLSL(s) and the measured actual load of the NLSLs in every hour. The NR ESS Energy Charge can be either positive or negative and is 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 i) the total measured load of the customer's NLSL(s) in an hour minus ii) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources in that same hour, minus iii) any energy amounts subject to the Unauthorized Increase Charge (GSRP II.N) in that same hour. The NR ESS Energy 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 Over-Schedule and Under-Schedule Charges

Load Following customers serving NLSLs with non-federal resources will be subject to i) an Hourly Over-Schedule Charge; ii) a Monthly Over-Schedule Charge; and iii) a Monthly Under-Schedule Charge, when specified thresholds are exceeded. The charges shall apply to the energy amounts that exceed each charge's respective threshold.

(1) Hourly Over-Schedule Charge

An Hourly Over-Schedule Charge shall apply in any hour where: (i) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources exceed (ii) the total measured load of the customer's NLSL(s) by more than the *OverThreshold*.

$$\begin{aligned} \text{OverThreshold} \\ = \text{Maximum}(\text{Minimum}(75 \text{ megawatthours}, 0.075 \\ \times \text{NLSL}_{\text{actual}}), 10 \text{ megawatthours}) \end{aligned}$$

Where:

OverThreshold = the hourly overschedule amount, in megawatthours, that is allowed without being subject to the Hourly Over-Schedule Charge

NLSL_{actual} = the total measured load, in megawatthours, of the customer's NLSL(s) in the hour

The Hourly Over-Schedule Charge is additive to the NR ESS Energy Charge, GRSP II.J.1.(b), applicable to the same hour.

(A) Hourly Over-Schedule Rate

The greater of: i) 20 mills/kWh, or ii) 25 percent of the absolute value of the NR ESS Energy Rate for the same hour as specified in GRSP II.J.1.(b).(2).

(B) Hourly Over-Schedule Billing Determinant

The Hourly Over-Schedule Billing Determinant is equal to:

- (i) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources in an hour, less
- (ii) the total measured load of the customer's NLSL(s) in the same hour, less
- (iii) the *OverThreshold* for the same hour.

(2) Monthly Over-Schedule Charge

A Monthly Over-Schedule Charge shall apply in any month where i) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources exceed ii) the total measured load of the customer's NLSL(s) by more than the greater of a) 1.5 percent of the total measured load of the customer's NLSL(s) in that same month, and b) 1,488 MWh.

The Monthly Over-Schedule Charge is equal to the absolute value of the sum of the customer's NR ESS Energy Charges in the month, GRSP II.J.1.(b), multiplied by 15 percent.

(3) Monthly Under-Schedule Charge

A Monthly Under-Schedule Charge shall apply in any month where i) the total measured load of the customer's NLSL(s) exceeds ii) the energy amounts supplied to the NLSL(s) by the customer's non-federal resources by more than the greater of a) 1.5 percent of the total measured actual load of the customer's NLSL(s) in that same month, and b) 1,488 MWh.

The Monthly Under-Schedule Charge is equal to the absolute value of the sum of the customer's NR ESS Energy Charges in the month, GRSP II.J.1.(b), multiplied by 30 percent.

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 Remarketing 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 i) 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(ii) 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: i) BPA serves the customer by transfer service; and ii) 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: i) BPA serves the customer by transfer service; and ii) 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 (3) months in advance of the requested service date for load amounts up to 50 aMW and six (6) 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 (3) 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 in an hour 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, UAI Demand applies if more than four (4) 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 Merged 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:

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

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 CRAC Surcharge Rate will be added to the December through September monthly/diurnal PF Melded, IP and NR Energy Rrates 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		
	<i>Clark PUD</i>	<i>Emerald PUD</i>	<i>Snohomish PUD</i>
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 for 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 Merged 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 (i) Power RFR exceeds the Power RDC Threshold, and (ii) BPA RFR exceeds the BPA RDC Threshold.

For FY 2026, FY 2027, and FY 2028, the Administrator shall apply the Power RDC Amount to decrease rates through a Power DD in an amount that is equal to or less than the Power RDC Amount. 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 Power RDC Thresholds 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
2025	2026	\$746
2026	2027	\$746
2027	2028	\$746

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:

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

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 Merged, 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	\$370	\$37	\$40
2026	2027	\$370	\$37	\$40
2027	2028	\$370	\$37	\$40

2. Power FRP Surcharge Rate

1. Calculating the Power FRP Surcharge Rate

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

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

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.

2. 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.

3. 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.

4. 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 RHWL and the actual DSI Revenue Credit described in (b) and (c) below.

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

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

- (1)** the forecast Firm Surplus and Secondary Adjustment from Unused RHWL 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 RHWL Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWL Revenue = (Actual Unused RHWL – Forecast Unused RHWL) × 45.78 mills/kWh.

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

Forecast Unused RHWL = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWL 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 follows:

- (1)** the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-26 7(i) process; plus
- (2)** the forecast megawatthour amount used to calculate (1) above for the applicable fiscal year *minus* the actual megawatthour amount of DSI sales for the applicable fiscal year, and the result multiplied by – 6.88 mills/kWh.
- (3)** DSI Take-or-Pay revenues.

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

The -6.88 mills/kWh is calculated by the equation:

$$PFMEES - 8.94 \text{ mills/kWh}$$

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of 2.07 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); and the Court-Ordered Operation Rate Adder (GRSP II.AD).

See Appendix 1, 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		300,597	315,949	333,121
7	CRFM STUDIES		12,510	12,914	13,329
8	LONG-TERM CONTRACT GENERATING PROJECTS		30,482	35,637	32,550
9	Sub-Total		887,809	984,929	968,062
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	Sub-Total		48,626	49,387	50,172
15	Non-Operating Generation				
16	TROJAN DECOMMISSIONING		1,300	1,329	1,359
17	WNP-1&3 DECOMMISSIONING		1,400	1,431	1,463
18	Sub-Total		2,700	2,760	2,822
19	Gross Contracted Power Purchases				
20	PNCA HEADWATER BENEFITS		-	-	-
21	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)		-	-	-
22	Sub-Total		-	-	-
23	Bookout Adjustment to Power Purchases (omit)				
24	Augmentation Power Purchases (omit - calculated below)				
25	AUGMENTATION POWER PURCHASES		-	-	-
26	Sub-Total		-	-	-
27	Exchanges and Settlements				
28	RESIDENTIAL EXCHANGE PROGRAM (REP)		287,353	287,380	288,197
29	OTHER SETTLEMENTS		-	-	-
30	Sub-Total		287,353	287,380	288,197
31	Renewable Generation				
32	RENEWABLES (excludes KIII)		15,396	2,013	270
33	Sub-Total		15,396	2,013	270
34	Generation Conservation				
35	CONSERVATION ACQUISITION (Purchases)		65,385	65,385	86,513
36	CONSERVATION INFRASTRUCTURE		32,443	32,492	32,497
37	LOW INCOME WEATHERIZATION & TRIBAL		6,005	6,005	6,005
38	DISTRIBUTED ENERGY RESOURCES		500	500	500
39	MARKET TRANSFORMATION		15,000	15,000	15,000
40	Sub-Total		119,333	119,382	140,515
41	Power System Generation Sub-Total		1,361,217	1,445,851	1,450,038
42	Power Non-Generation Operations				
43	Power Services System Operations				
44	GENERATION PROJECT COORDINATION		4,501	4,615	4,732
45	SLICE IMPLEMENTATION		835	863	891
46	Sub-Total		5,336	5,478	5,623
47	Power Services Scheduling				
48	OPERATIONS SCHEDULING		12,028	12,516	13,038
49	OPERATIONS PLANNING		11,861	12,170	12,499
50	Sub-Total		23,889	24,686	25,537
51	Power Services Marketing and Business Support				
52	GRID MOD		324	351	378
53	EIM INTERNAL SUPPORT		-	-	-
54	POWER INTERNAL SUPPORT		23,020	23,701	24,425
55	POWER R&D		2,156	2,156	2,156
56	SALES & SUPPORT		14,504	15,022	15,567
57	STRATEGY, FINANCE & RISK MGMT		4,385	6,496	6,364
58	EXECUTIVE AND ADMINISTRATIVE SERVICES		-	-	-
59	CONSERVATION SUPPORT		9,555	9,869	10,189
60	Sub-Total		53,943	57,595	59,079
61	Power Non-Generation Operations Sub-Total		83,167	87,759	90,240

Table F, continued
Composite Cost Pool True-Up Table

		Actual Data (\$000)	FY 2026 forecast (\$000)	FY 2027 forecast (\$000)	FY 2028 forecast (\$000)
62	Power Services Transmission Acquisition and Ancillary Services				
63	TRANSMISSION and ANCILLARY Services - System Obligations		2,304	2,428	2,805
64	3RD PARTY GTA WHEELING (All)		92,013	94,644	96,736
65	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)		3,300	3,300	3,300
66	TRANS ACQ GENERATION INTEGRATION		23,492	24,627	26,376
67	TELEMETERING/EQUIP REPLACEMT		-	-	-
68	Power Services Trans Acquisition and Ancillary Serv Sub-Total		121,109	124,999	129,217
69	Fish and Wildlife/USF&W/Planning Council/Environmental Req				
70	FISH & WILDLIFE		275,484	282,484	289,505
71	USF&W LOWER SNAKE HATCHERIES		33,777	34,707	35,669
72	PLANNING COUNCIL		12,041	11,876	12,052
73	LONG TERM FUNDING AGREEMENTS		18,403	18,075	19,063
74	Fish and Wildlife/USF&W/Planning Council Sub-Total		339,705	347,141	356,288
75	BPA Internal Support				
76	Additional Post-Retirement Contribution		16,442	17,182	17,927
77	Agency Services G&A (excludes direct project support)		141,885	152,698	158,623
78	BPA Internal Support Sub-Total		158,328	169,880	176,550
79	Bad Debt Expense		-	-	-
80	Other Income, Expenses, Adjustments		-	-	-
81	Depreciation		148,559	152,451	156,446
82	Amortization		334,392	358,406	383,068
83	Accretion		42,607	44,438	46,350
84	Total Operating Expenses		2,589,084	2,730,926	2,788,199
86	Other Expenses				
87	Net Interest Expense		180,472	176,275	171,422
88	Irrigation assistance		20,662	6,370	11,634
89	LDD		42,155	43,297	44,391
90	Irrigation Rate Discount Costs		22,034	22,034	22,034
91	Sub-Total		265,323	247,975	249,481
92	Total Expenses		2,854,407	2,978,901	3,037,679
94	Revenue Credits				
95	Generation Inputs for Ancillary, Control Area, and Other Services Revenues		133,219	133,219	133,219
96	Downstream Benefits and Pumping Power revenues		21,193	21,193	21,193
97	4(h)(10)(c) credit		124,911	131,117	132,163
98	PRSC Net Credit (Composite)		-	-	-
99	Colville and Spokane Settlements		4,600	4,600	4,600
100	NR Revenues from ESS (Capacity)		9,502	11,522	14,047
101	FPS Real Power Losses (Capacity)		44,745	44,745	44,745
102	Miscellaneous revenues		8,647	8,831	9,078
103	Renewable Energy Certificates		-	-	-
104	Net Revenues from other Designated BPA System Obligations (Upper Baker)		485	476	456
105	RSS Revenues		3,416	5,234	5,646
106	Firm Surplus and Secondary Adjustment (from Unused RHWM)		94,894	73,857	60,238
107	Balancing Augmentation Adjustment		834	3,383	686
108	Transmission Loss Adjustment		35,579	35,836	35,988
109	Tier 2 Rate Adjustment		8,243	9,667	10,488
110	NR Revenues (Firm Energy)		706	19,072	24,877
111	Total Revenue Credits		490,973	502,751	497,423

Table F, continued
Composite Cost Pool True-Up Table

	Actual Data (\$000)	FY 2026 forecast (\$000)	FY 2027 forecast (\$000)	FY 2028 forecast (\$000)
113 Augmentation Costs (not subject to True-Up)				
114 Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)		11,347	13,030	4,577
115 Augmentation Purchases (including Other Augmentation)		7,021	17,440	20,974
116 Total Augmentation Costs		18,368	30,470	25,551
118 DSI Revenue Credit				
119 Revenues 11aMW @ IP rate		4,393	4,393	4,405
120 Total DSI revenues		4,393	4,393	4,405
122 Minimum Required Net Revenue Calculation				
123 Principal Payment of Fed Debt for Power		437,000	441,000	584,999
124 Repayment of Non-Federal Obligations (EN Line of Credit)		-	-	-
125 Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)		36,161	39,551	35,031
126 Sub-Total		473,161	480,551	620,030
127 Depreciation		148,559	152,451	156,446
128 Amortization		334,392	358,406	383,068
129 Accretion		42,607	44,438	46,350
130 Capitalization Adjustment		(45,937)	(45,937)	(45,937)
131 Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)		(42,053)	(44,109)	(45,757)
132 Amortization of Cost of Issuance (MRNR-reverse sign)		208	308	408
133 Gains/Losses on Extinguishment		-	-	-
134 Payments for Litigation Stay Agreements		(10,600)	(10,843)	(11,079)
135 Amortization of P2IP Settlement Payments		14,222	14,222	14,222
136 Non-Cash Expenses		-	-	-
137 Prepay Revenue Credits		(30,600)	(30,600)	(30,600)
138 Non-Federal Interest (Prepay)		3,329	2,064	740
139 Contribution to decommissioning trust fund		(15,700)	(16,300)	(17,000)
140 Gains/losses on decommissioning trust fund		(16,849)	(17,824)	(18,855)
141 Interest earned on decommissioning trust fund		-	-	-
142 Revenue Financing Requirement		(39,000)	(43,000)	(44,000)
143 Sub-Total		342,578	363,276	388,007
144 Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses		130,583	117,275	232,024
145 Minimum Required Net Revenues		130,583	117,275	232,024
146				
147 Annual Composite Cost Pool (Amounts for each FY)		2,507,992	2,619,501	2,793,425
148				
149 SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL				
150 TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)				
151 Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)				
152 TRUE-UP ADJUSTMENT CHARGE BILLED (11.74505 percent)				

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	54,465,330
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

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

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 \$861,993,059 (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	42.49%	56.87%	0.64%
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 56.29 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 68.51 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	46.04	44.26	13.81
November	34.94	37.05	10.78
December	43.04	44.20	12.99
January	38.97	39.21	11.88
February	40.84	44.59	12.39
March	24.60	29.95	7.97
April	17.74	22.50	6.09
May	4.01	8.14	2.35
June	10.51	11.49	4.12
July	46.39	43.47	13.91
August	49.21	45.73	14.67
September	55.92	54.47	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); ~~and~~

[the Court-Ordered Operation Rate Adder \(GRSP II.AD\)](#). See Appendix 1, 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 will 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 i) fails to register with the Washington (WA) Department of Ecology and therefore does not receive an allocation of no-cost allowances, or ii) 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
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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 CO₂e/MWh).

Unit cost of allowances = Auction settlement price or secondary market price for allowances (one allowance covers the compliance obligation for 1 MT CO₂e), 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 -4.48 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: i) an approved exclusion attestation for the NLSL in accordance with the WRAP and approved by BPA; or ii) 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 4.48 mills/kWh.

(b) Billing Determinant

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

Other Rate Adjustments

AD. Court-Ordered Operation Rate Adder

The Court-Ordered Operation Rate Adder (COORA) and COORA True-Up apply to the following products under the PF-26 Rate Schedule: Load Following, Block, and the Block portion of Slice/Block. The COORA and COORA True-Up also apply to power purchased at the PF Melded Rate (PF-26), Industrial Firm Power Rate (IP-26), and New Resource Firm Power Rate (NR-26).

As specified below, the COORA and COORA True-Up will adjust the PF Tier 1 Equivalent Energy Rates (GRSP II.AA), the Load Shaping Charge True-Up Rate (GRSP II.E, Section 1), and the PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section 1(c)) for Fiscal Years 2027 and 2028 (the “applicable years”).

The COORA will begin at the start of the month immediately following the month that BPA receives FERC interim approval.

1. COORA

(a) COORA Energy Rate

The COORA Energy Rate applicable to Fiscal Year 2027 is calculated with the following formula:

$$\frac{\left[\frac{\$125 \text{ million}}{(1 - \text{ApplicableLDD})} \right]}{\sum \text{RemainingFY2027BD}}$$

Where:

ApplicableLDD is the average customer Low Density Discount weighted by customer-specific billing determinants applicable to the COORA.

$\sum \text{RemainingFY2027BD}$ is the sum of the Fiscal Year 2027 forecast billing determinants applicable to the COORA as calculated using Appendix 2: Forecast COORA Billing Determinants.

The COORA Energy Rate applicable to Fiscal Year 2028 is 2.42 mills/kWh

(b) COORA Billing Determinant

For customers taking service at the PF Melded, IP, and NR rates, the COORA Energy Rate will be added to any energy purchased at the PF Melded, IP and NR energy rates.

For PF customers with a System Shaped Load, the COORA Energy Rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for every month.

A customer's Low Density Discount will be applied to the COORA Energy Rate in each applicable year.

(c) Annual Effective COORA Energy Rate

The Annual Effective COORA Energy Rate applicable to Fiscal Year 2027 is 2.44 mills/kWh

The Annual Effective COORA Energy Rate applicable to Fiscal Year 2028 is 2.42 mills/kWh

(d) Other COORA Applicable Rates

- (1)** The applicable Fiscal Year COORA Energy Rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent Energy Rates (GRSP II.AA) that the COORA is applicable.
- (2)** The applicable Annual Effective COORA Energy Rate will be subtracted from the Load Shaping True-Up Rate in each Fiscal Year (GRSP II.E, Section 1).
- (3)** The applicable Fiscal Year Annual Effective COORA Energy Rate will be subtracted from the PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section 1(c)).

(e) COORA Suspension, Reinstatement, and Reduction Provision

- (1)** **Suspension.** The COORA will automatically suspend at the beginning of the next month if court-ordered operations are either stayed or are no longer in effect. For example, the COORA will suspend on the first hour of August first if the court-ordered operations are stayed anytime in the prior July.

- (2) Reinstatement.** The COORA will automatically be reinstated at the beginning of the next month if court-ordered operations are reinstated or other operational agreement is reached. For example, the COORA will be reinstated on the first hour of September first if the court-ordered operations are reinstated anytime in the prior August.
- (3) Reduction.** The COORA may be reduced by the Administrator at the beginning of any month if BPA's operations are materially different than the Amended Preliminary Injunction Order issued on March 2, 2026 by the U.S. District Court for the District of Oregon.

If the COORA is not applicable for an entire fiscal year, or is reduced by the Administrator for any portion of a fiscal year, BPA will replace the Annual Effective COORA Energy Rate with a Partial COORA Energy Rate that takes into account the effective annual reduction in the size of the COORA for purpose of subtracting from the Load Shaping True-Up Rate (GRSP II.E, Section 1) and PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section -1(c)).

2. COORA True-Up

A COORA True-Up will be applied at the end of each applicable year. At the end of the applicable year, BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR). -Based on the calculations below, a COORA True-Up will trigger when Power RFR are above \$556 million, resulting in a bill credit applicable to customers that paid the COORA. The credit will be a single amount issued as soon as practical and after BPA's audited actual financial data are available (usually in late November). No interest shall be applied to any COORA True-Up amount.

The COORA True-Up will also adjust the Load Shaping True-Up Rate (GRSP II.E, Section 1) and the PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section -1(c)).

(a) Total COORA True-Up Amount

The Total COORA True-Up Amount paid to customers via a bill credit shall be equal to the lesser of:

- (1)** The amount of Power RFR in excess of \$556 million, or;
- (2)** The total COORA amount paid over the applicable year (GRSP II.AD.1), as adjusted for Low Density Discount (GRSP II.B) and any load subject to the Load Shaping Charge True-Up Adjustment (GRSP II.E), rounded down to the nearest dollar.

(b) Customer COORA True-Up Share

Each customer's share of the Total COORA True-Up Amount will be:

$$CustomerShare = TotalCOORA_{TUA} \times \frac{CustomerCOORApaid}{TotalCustomerCOORApaid}$$

Where:

CustomerShare is the a-customer's dollar credit rounded down to the nearest dollar.

TotalCOORA_{TUA} is the Total COORA True-Up Amount rounded down to the nearest dollar.

CustomerCOORApaid is the total COORA amount the customer paid by the customer over the applicable year, as adjusted for Low Density Discount (GRSP II.B) and any load subject to the Load Shaping Charge True-Up Adjustment (GRSP II.E), rounded down to the nearest dollar.

TotalCustomerCOORApaid is the total COORA amount all customers paid by all customers over the applicable year, as adjusted for Low Density Discount (GRSP II.B) and any load subject to the Load Shaping Charge True-Up Adjustment (GRSP II.E), rounded down to the nearest dollar.

In the event the CustomerShare exceeds the customer's total Power bill in a month, BPA will pay the remaining True-Up Amount in subsequent bills with any remainder owed at the end of the year paid via electronic payment to applicable customers.

(c) Other COORA True-Up Applicable Rates

A mills per kilowatthour COORA True-Up Rate will be calculated as:

$$COORA_{TUR} = \frac{TotalCOORA_{TUA}}{ApplicablekWh}$$

Where:

COORA_{TUR} is a mills per kilowatthour COORA True-Up Rate, rounded to the nearest hundredth of a mill.

TotalCOORA_{TUA} is the Total COORA True-Up Amount rounded down to the nearest dollar.

ApplicablekWh is the applicable year's kilowatthour annual sum of Forecast COORA Billing Determinants as specified in Appendix 2: Forecast COORA Billing Determinants (as adjusted for the Load Shaping Charge True-Up Adjustment (GRSP II.E)).

(1) The COORA True-Up Energy Rate will be added to the Load Shaping True-Up Rate (GRSP II.E, Section 1)

(2) The COORA True-Up Energy Rate will be added to the PF Melded Equivalent Energy Scalar Rate (GRSP II.R, Section 1(c))

(3) COORA True-Up 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 COORA True-Up Amountforecast of its end of year financial reserves.

(d) Notification of COORA True-Up

If the COORA True-Up triggers, BPA will notify customers of the COORA True-Up aAmount to be paid to customers. Such notice and payment will be provided as soon as practicable and after BPA's audited actual financial data are available (usually in late November). BPA will make available to customers the data relied upon to calculate the Total COORA True-Up Amount and Customer COORA True-Up Share.

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 RHW in the RHW 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 i) 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 ii) 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. RHEM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHEM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHEM 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 three-hour periods each day or a single six-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 RHEM 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 rate-setting year that i) results in an increase in the customer's load placed on BPA during the ensuing Rate Period, and ii) 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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APPENDICES

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Appendix 1: 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), and the Court-Ordered Operation Rate Adder (GRSP II.AD) 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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Appendix 2: Forecast COORA Billing Determinants

Sum of Billing Determinants (MWh)															
	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
IP Load	8,184	7,931	8,184	8,184	7,392	8,173	7,920	8,184	7,920	8,184	8,184	7,920	8,184	7,931	8,184
NR Load	6,193	11,964	14,701	14,198	13,534	22,092	20,841	13,173	12,251	12,341	7,237	22,770	25,921	10,366	16,515
	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total					
IP Load	8,184	7,656	8,173	7,920	8,184	7,920	8,184	8,184	7,920	192,984					
NR Load	17,085	16,514	18,200	18,188	19,363	19,291	20,502	21,072	20,946	395,258					

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10015	Asotin County PUD #1	337.004	430.848	489.838	516.817	411.856	450.244	348.943	451.590	461.233	410.537	421.136	327.063	337.004	430.848	489.838
10024	Benton County PUD #1	117,967.360	150,817.387	171,466.755	180,910.812	144,169.589	157,606.967	122,146.984	158,078.310	161,453.742	143,707.793	147,417.841	114,487.625	117,967.360	150,817.387	171,466.755
10025	Benton REA	35,027.597	44,781.630	50,912.968	53,717.156	42,807.725	46,797.635	36,268.637	46,937.588	47,939.842	42,670.606	43,772.216	33,994.373	35,027.597	44,781.630	50,912.968
10027	Big Bend Elec Coop	35,928.624	45,933.565	52,222.621	55,098.941	43,908.883	48,001.427	37,201.588	48,144.981	49,173.016	43,768.238	44,898.184	34,868.822	35,928.624	45,933.565	52,222.621
10029	Blachly Lane Elec Coop	10,342.932	13,223.098	15,033.556	15,861.575	12,640.244	13,818.383	10,709.385	13,859.708	14,155.653	12,599.756	12,925.039	10,037.842	10,342.932	13,223.098	15,033.556
10044	Canby, City of	11,923.777	15,244.156	17,331.329	18,285.906	14,572.216	15,930.425	12,346.240	15,978.067	16,319.246	14,525.540	14,900.540	11,572.056	11,923.777	15,244.156	17,331.329
10046	Central Electric Coop	48,057.010	61,439.306	69,851.352	73,698.629	58,731.156	64,205.214	49,759.687	64,397.228	65,772.296	58,543.032	60,054.414	46,639.452	48,057.010	61,439.306	69,851.352
10047	Central Lincoln PUD	88,540.575	113,196.212	128,694.625	135,782.876	108,206.697	118,292.141	91,677.599	118,645.908	121,179.344	107,860.096	110,644.677	85,928.855	88,717.793	113,422.778	128,952.213
10055	Albion, City of	233.661	298.728	339.629	358.335	285.560	312.177	241.940	313.110	319.796	284.646	291.994	226.769	233.661	298.728	339.629
10057	Ashland, City of	11,218.642	14,342.665	16,306.410	17,204.537	13,710.463	14,988.351	11,616.123	15,033.176	15,354.178	13,666.546	14,019.370	10,887.721	11,221.547	14,346.379	16,310.633
10059	Bandon, City of	4,485.215	5,734.201	6,519.306	6,878.377	5,481.446	5,992.346	4,644.128	6,010.267	6,138.604	5,463.888	5,604.947	4,352.913	4,485.215	5,734.201	6,519.306
10061	Blaine, City of	5,135.151	6,565.121	7,463.994	7,875.096	6,275.741	6,860.674	5,317.091	6,881.191	7,028.124	6,255.639	6,417.139	4,983.677	5,135.151	6,565.121	7,463.994
10062	Bonnors Ferry, City of	3,123.091	3,992.769	4,539.445	4,789.469	3,816.775	4,172.518	3,233.743	4,184.997	4,274.359	3,804.549	3,902.770	3,030.968	3,123.091	3,992.769	4,539.445
10064	Burley, City of	8,257.413	10,556.830	12,002.232	12,663.292	10,091.501	11,032.083	8,549.976	11,065.076	11,301.348	10,059.177	10,318.871	8,013.840	8,257.413	10,556.830	12,002.232
10065	Cascade Locks, City of	1,395.742	1,784.410	2,028.725	2,140.463	1,705.756	1,864.742	1,445.193	1,870.318	1,910.254	1,700.293	1,744.188	1,354.571	1,395.742	1,784.410	2,028.725

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10066	Centralia, City of	14,309.361	18,294.048	20,798.803	21,944.360	17,487.674	19,117.619	14,816.347	19,174.793	19,584.231	17,431.659	17,881.686	13,887.272	14,309.361	18,294.048	20,798.803
10067	Cheney, City of	9,286.683	11,872.719	13,498.289	14,241.748	11,349.388	12,407.212	9,615.714	12,444.317	12,710.040	11,313.035	11,605.098	9,012.750	9,286.683	11,872.719	13,498.289
10068	Chewelah, City of	1,471.277	1,880.979	2,138.516	2,256.301	1,798.069	1,965.659	1,523.405	1,971.537	2,013.635	1,792.309	1,838.580	1,427.878	1,470.447	1,879.918	2,137.309
10070	Declo, City of	210.835	269.545	306.450	323.329	257.664	281.679	218.304	282.522	288.555	256.839	263.469	204.616	210.835	269.545	306.450
10071	Drain, City of	1,109.787	1,418.826	1,613.087	1,701.932	1,356.286	1,482.700	1,149.107	1,487.134	1,518.889	1,351.942	1,386.845	1,077.051	1,109.787	1,418.826	1,613.087
10072	Ellensburg, City of	14,080.266	18,001.156	20,465.809	21,593.027	17,207.693	18,811.542	14,579.134	18,867.800	19,270.683	17,152.574	17,595.395	13,664.934	14,080.266	18,001.156	20,465.809
10074	Forest Grove, City of	15,665.676	20,028.051	22,770.218	24,024.358	19,145.245	20,929.684	16,220.716	20,992.277	21,440.524	19,083.920	19,576.602	15,203.578	15,665.676	20,028.051	22,770.218
10076	Heyburn, City of	2,828.421	3,616.043	4,111.138	4,337.572	3,456.653	3,778.832	2,928.633	3,790.133	3,871.064	3,445.582	3,534.535	2,744.990	2,828.421	3,616.043	4,111.138
10078	McCleary, City of	2,177.241	2,783.530	3,164.642	3,338.944	2,660.837	2,908.841	2,254.382	2,917.540	2,979.839	2,652.314	2,720.788	2,113.018	2,182.636	2,790.429	3,172.484
10079	McMinnville, City of	49,366.011	63,112.820	71,753.998	75,706.069	60,330.904	65,954.068	51,115.066	66,151.312	67,563.834	60,137.656	61,690.206	47,909.840	49,360.616	63,105.922	71,746.156
10080	Milton, Town of	3,892.554	4,976.503	5,657.868	5,969.493	4,757.146	5,200.538	4,030.470	5,216.091	5,327.469	4,741.909	4,864.329	3,777.734	3,893.800	4,978.095	5,659.677
10081	Milton-Freewater, City of	5,454.723	6,973.684	7,928.496	8,365.181	6,666.294	7,287.629	5,647.986	7,309.424	7,465.501	6,644.942	6,816.491	5,293.823	5,453.893	6,972.623	7,927.288
10082	Minidoka, City of	67.649	86.488	98.329	103.746	82.676	90.381	70.046	90.652	92.587	82.411	84.539	65.654	67.235	85.958	97.727
10083	Monmouth, City of	4,910.205	6,277.535	7,137.034	7,530.128	6,000.832	6,560.141	5,084.176	6,579.760	6,720.258	5,981.611	6,136.035	4,765.366	4,910.205	6,277.535	7,137.034
10086	Plummer, City of	1,493.689	1,909.631	2,171.092	2,290.671	1,825.458	1,995.600	1,546.610	2,001.569	2,044.308	1,819.611	1,866.587	1,449.628	1,497.424	1,914.407	2,176.521
10087	Port Angeles, City of	28,533.228	36,478.792	41,473.335	43,757.606	34,870.863	38,121.014	29,544.169	38,235.019	39,051.449	34,759.167	35,656.530	27,691.570	28,533.642	36,479.323	41,473.939
10089	Richland, City of	61,186.445	78,224.856	88,935.119	93,833.493	74,776.825	81,746.425	63,354.302	81,990.899	83,741.643	74,537.304	76,461.604	59,381.602	61,186.445	78,224.856	88,935.119
10091	Rupert, City of	5,521.128	7,058.580	8,025.015	8,467.017	6,747.449	7,376.347	5,716.743	7,398.407	7,556.384	6,725.835	6,899.474	5,358.268	5,519.883	7,056.988	8,023.205
10094	Soda Springs, City of	1,632.723	2,087.383	2,373.180	2,503.890	1,995.374	2,181.354	1,690.572	2,187.877	2,234.595	1,988.982	2,040.331	1,584.562	1,636.873	2,092.688	2,379.212
10095	Sumas, Town of	2,139.058	2,734.716	3,109.143	3,280.389	2,614.173	2,857.829	2,214.846	2,866.375	2,927.581	2,605.800	2,673.073	2,075.962	2,139.058	2,734.716	3,109.143
10097	Troy, City of	1,171.626	1,497.886	1,702.970	1,796.767	1,431.861	1,565.318	1,213.138	1,570.000	1,603.523	1,427.274	1,464.122	1,137.067	1,173.286	1,500.008	1,705.383
10101	Clallam County PUD #1	44,638.003	57,068.218	64,881.791	68,455.354	54,552.739	59,637.346	46,219.543	59,815.700	61,092.938	54,377.999	55,781.854	43,321.296	44,638.003	57,068.218	64,881.791
10103	Clark County PUD #1	186,996.189	239,068.473	271,800.858	286,771.122	228,530.702	249,830.987	193,621.529	250,578.138	255,928.711	227,798.687	233,679.676	181,480.280	186,996.189	239,068.473	271,800.858
10105	Clatskanie PUD	20,486.650	26,191.508	29,777.554	31,417.643	25,037.026	27,370.611	21,212.499	27,452.466	28,038.657	24,956.829	25,601.129	19,882.346	20,652.246	26,403.217	30,018.250
10106	Clearwater Power	14,019.671	17,923.689	20,377.735	21,500.101	17,133.640	18,730.587	14,516.394	18,786.603	19,187.752	17,078.758	17,519.674	13,606.127	14,019.671	17,923.689	20,377.735
10109	Columbia Basin Elec Coop	7,114.838	9,096.087	10,341.489	10,911.079	8,695.145	9,505.579	7,366.919	9,534.006	9,737.585	8,667.293	8,891.053	6,904.968	7,114.838	9,096.087	10,341.489
10111	Columbia Power Coop	1,877.175	2,399.907	2,728.493	2,878.773	2,294.122	2,507.947	1,943.684	2,515.447	2,569.159	2,286.774	2,345.811	1,821.803	1,878.005	2,400.968	2,729.700

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10112	Columbia River PUD	34,200.445	43,724.143	49,710.694	52,448.663	41,796.851	45,692.541	35,412.179	45,829.189	46,807.776	41,662.970	42,738.565	33,191.619	34,200.445	43,724.143	49,710.694
10113	Columbia REA	22,130.579	28,293.217	32,167.021	33,938.718	27,046.095	29,566.936	22,914.672	29,655.360	30,288.588	26,959.462	27,655.465	21,477.783	22,130.579	28,293.217	32,167.021
10116	Consolidated Irrigation District #19	133.640	170.853	194.246	204.944	163.322	178.545	138.374	179.079	182.903	162.799	167.002	129.697	133.640	170.853	194.246
10118	Consumers Power	26,816.253	34,283.697	38,977.696	41,124.513	32,772.525	35,827.100	27,766.362	35,934.244	36,701.545	32,667.550	33,510.915	26,025.243	26,816.253	34,283.697	38,977.696
10121	Coos Curry Elec Coop	23,460.745	29,993.791	34,100.432	35,978.617	28,671.711	31,344.069	24,291.968	31,437.806	32,109.095	28,579.872	29,317.707	22,768.714	23,459.086	29,991.669	34,098.019
10123	Cowlitz County PUD #1	103,842.271	132,758.926	150,935.796	159,249.046	126,907.117	138,735.540	107,521.438	139,150.445	142,121.713	126,500.616	129,766.432	100,779.190	103,367.063	132,151.388	150,245.076
10136	Douglas Electric Cooperative	10,814.819	13,826.390	15,719.450	16,585.246	13,216.945	14,448.835	11,197.992	14,492.046	14,801.493	13,174.609	13,514.733	10,495.810	10,846.362	13,866.716	15,765.297
10142	East End Mutual Electric	1,577.524	2,016.813	2,292.947	2,419.239	1,927.915	2,107.607	1,633.417	2,113.910	2,159.048	1,921.739	1,971.352	1,530.992	1,577.524	2,016.813	2,292.947
10144	Eatonville, City of	1,938.600	2,478.435	2,817.774	2,972.971	2,369.190	2,590.011	2,007.284	2,597.757	2,653.226	2,361.601	2,422.570	1,881.415	1,936.939	2,476.313	2,815.361
10156	Elmhurst Mutual P & L	18,927.801	24,198.572	27,511.751	29,027.046	23,131.936	25,287.956	19,598.421	25,363.582	25,905.169	23,057.841	23,653.116	18,369.480	18,927.801	24,198.572	27,511.751
10157	Emerald PUD	29,331.742	37,499.668	42,633.986	44,982.183	35,846.740	39,187.848	30,370.977	39,305.044	40,144.321	35,731.918	36,654.395	28,466.531	29,331.742	37,499.668	42,633.986
10158	Energy Northwest	1,323.942	1,692.616	1,924.363	2,030.353	1,618.008	1,768.815	1,370.850	1,774.105	1,811.987	1,612.825	1,654.463	1,284.889	1,323.527	1,692.086	1,923.760
10170	Eugene Water & Electric Board	73,069.133	93,416.482	106,206.727	112,056.388	89,298.827	97,621.956	75,657.999	97,913.907	100,004.654	89,012.791	91,310.799	70,913.781	73,069.133	93,416.482	106,206.727
10172	U.S. Airforce Base, Fairchild	3,072.457	3,928.036	4,465.849	4,711.819	3,754.895	4,104.870	3,181.316	4,117.147	4,205.060	3,742.867	3,839.496	2,981.828	3,085.324	3,944.484	4,484.549
10173	Fall River Elec Coop	19,451.568	24,868.189	28,273.051	29,830.277	23,772.038	25,987.719	20,140.744	26,065.439	26,622.012	23,695.893	24,307.640	18,877.796	19,451.568	24,868.189	28,273.051
10174	Farmers Elec Coop	297.575	380.440	432.530	456.352	363.672	397.567	308.119	398.756	407.271	362.506	371.865	288.798	297.575	380.440	432.530
10177	Ferry County PUD #1	5,665.973	7,243.760	8,235.549	8,689.147	6,924.465	7,569.863	5,866.720	7,592.502	7,754.623	6,902.286	7,080.480	5,498.841	5,691.704	7,276.657	8,272.951
10179	Flathead Elec Coop	97,945.957	125,220.683	142,365.444	150,206.656	119,701.148	130,857.936	101,416.216	131,249.283	134,051.837	119,317.728	122,398.107	95,056.803	97,945.957	125,220.683	142,365.444
10183	Franklin County PUD #1	36,603.046	46,795.791	53,202.900	56,133.212	44,733.104	48,902.469	37,899.905	49,048.718	50,096.051	44,589.818	45,740.976	35,523.350	36,603.046	46,795.791	53,202.900
10186	Glacier Elec Coop	10,794.483	13,800.391	15,689.890	16,554.060	13,192.091	14,421.664	11,176.935	14,464.795	14,773.660	13,149.835	13,489.319	10,476.073	10,793.238	13,798.799	15,688.081
10190	Grant County PUD #2	3,047.971	3,896.731	4,430.257	4,674.267	3,724.969	4,072.156	3,155.962	4,084.334	4,171.547	3,713.037	3,808.896	2,958.063	3,047.971	3,896.731	4,430.257
10191	Grays Harbor PUD #1	74,388.925	95,103.792	108,125.058	114,080.376	90,911.763	99,385.227	77,024.550	99,682.451	101,810.961	90,620.560	92,960.075	72,194.642	74,406.356	95,126.078	108,150.394
10197	Harney Elec Coop	13,358.945	17,078.973	19,417.363	20,486.834	16,326.157	17,847.843	13,832.258	17,901.219	18,283.462	16,273.863	16,693.999	12,964.891	13,358.945	17,078.973	19,417.363
10202	Hood River Elec Coop	7,690.483	9,832.029	11,178.195	11,793.868	9,398.649	10,274.653	7,962.960	10,305.381	10,525.431	9,368.544	9,610.408	7,463.633	7,690.483	9,832.029	11,178.195
10203	Idaho County L & P	3,648.103	4,663.980	5,302.555	5,594.609	4,458.398	4,873.945	3,777.356	4,888.521	4,992.905	4,444.117	4,558.849	3,540.493	3,648.103	4,663.980	5,302.555
10204	Idaho Falls Power	23,950.065	30,619.369	34,811.662	36,729.021	29,269.715	31,997.809	24,798.624	32,093.502	32,778.792	29,175.960	29,929.184	23,243.599	23,950.065	30,619.369	34,811.662

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10209	Inland P & L	61,584.043	78,733.172	89,513.031	94,443.235	75,262.735	82,277.624	63,765.987	82,523.686	84,285.807	75,021.658	76,958.462	59,767.471	61,584.043	78,733.172	89,513.031
10230	Kittitas County PUD #1	5,696.270	7,282.493	8,279.586	8,735.610	6,961.492	7,610.341	5,898.091	7,633.100	7,796.089	6,939.193	7,118.340	5,528.245	5,696.270	7,282.493	8,279.586
10231	Klickitat County PUD #1	21,523.392	27,516.947	31,284.468	33,007.556	26,304.043	28,755.721	22,285.973	28,841.718	29,457.572	26,219.788	26,896.693	20,888.507	21,523.392	27,516.947	31,284.468
10234	Kootenai Electric Coop	29,943.081	38,281.243	43,522.571	45,919.710	36,593.865	40,004.608	31,003.974	40,124.247	40,981.016	36,476.649	37,418.352	29,059.836	29,943.081	38,281.243	43,522.571
10235	Lakeview L & P (WA)	17,836.276	22,803.092	25,925.208	27,353.119	21,797.966	23,829.654	18,468.221	23,900.920	24,411.273	21,728.145	22,289.092	17,310.151	17,871.138	22,847.662	25,975.881
10236	Lane County Elec Coop	17,087.150	21,845.357	24,836.345	26,204.282	20,882.448	22,828.804	17,692.553	22,897.076	23,385.996	20,815.559	21,352.946	16,583.122	17,087.150	21,845.357	24,836.345
10237	Lewis County PUD #1	26,951.553	34,456.673	39,174.355	41,332.003	32,937.876	36,007.862	27,906.455	36,115.549	36,886.721	32,832.371	33,679.992	26,156.551	26,951.553	34,456.673	39,174.355
10239	Lincoln Elec Coop (MT)	8,220.059	10,509.076	11,947.940	12,606.010	10,045.851	10,982.179	8,511.299	11,015.023	11,250.225	10,013.674	10,272.193	7,977.589	8,220.059	10,509.076	11,947.940
10242	Lost River Elec Coop	5,592.927	7,150.373	8,129.377	8,577.127	6,835.197	7,472.273	5,791.087	7,494.620	7,654.652	6,813.302	6,989.199	5,427.950	5,592.927	7,150.373	8,129.377
10244	Lower Valley Energy	50,514.811	64,581.523	73,423.790	77,467.830	61,734.869	67,488.889	52,304.568	67,690.723	69,136.117	61,537.123	63,125.803	49,024.753	50,514.811	64,581.523	73,423.790
10246	Mason County PUD #1	5,276.676	6,746.056	7,669.702	8,092.134	6,448.701	7,049.754	5,463.630	7,070.837	7,221.820	6,428.044	6,593.994	5,121.027	5,276.676	6,746.056	7,669.702
10247	Mason County PUD #3	46,928.132	59,996.072	68,210.516	71,967.420	57,351.538	62,697.008	48,590.812	62,884.511	64,227.278	57,167.832	58,643.712	45,543.872	46,928.132	59,996.072	68,210.516
10256	Midstate Elec Coop	27,445.437	35,088.088	39,892.221	42,089.407	33,541.459	36,667.702	28,417.838	36,777.362	37,562.666	33,434.021	34,297.173	26,635.867	27,445.437	35,088.088	39,892.221
10258	Mission Valley	22,282.894	28,487.947	32,388.413	34,172.304	27,232.242	29,770.433	23,072.385	29,859.464	30,497.052	27,145.013	27,845.806	21,625.606	22,282.894	28,487.947	32,388.413
10259	Missoula Elec Coop	15,843.723	20,255.678	23,029.012	24,297.406	19,362.839	21,167.560	16,405.072	21,230.864	21,684.204	19,300.817	19,799.099	15,376.373	15,843.723	20,255.678	23,029.012
10260	Modern Elec Coop	15,432.429	19,729.853	22,431.192	23,666.660	18,860.192	20,618.062	15,979.206	20,679.724	21,121.295	18,799.780	19,285.126	14,977.212	15,432.429	19,729.853	22,431.192
10273	Nespelem Valley Elec Coop	3,453.040	4,414.598	5,019.028	5,295.466	4,220.008	4,613.336	3,575.381	4,627.133	4,725.935	4,206.491	4,315.088	3,351.183	3,453.040	4,414.598	5,019.028
10278	Northern Lights	21,094.252	26,968.307	30,660.709	32,349.442	25,779.585	28,182.380	21,841.629	28,266.664	28,870.239	25,697.010	26,360.419	20,472.025	21,094.252	26,968.307	30,660.709
10279	Northern Wasco County PUD	38,024.936	48,613.628	55,269.629	58,313.773	46,470.815	50,802.143	39,372.172	50,954.073	52,042.090	46,321.961	47,517.838	36,903.297	38,024.936	48,613.628	55,269.629
10284	Ohop Mutual Light Company	6,286.025	8,036.477	9,136.803	9,640.039	7,682.241	8,398.267	6,508.741	8,423.383	8,603.247	7,657.634	7,855.328	6,100.604	6,286.025	8,036.477	9,136.803
10285	Okanogan County Elec Coop	3,832.790	4,900.097	5,571.000	5,877.839	4,684.108	5,120.692	3,968.588	5,136.006	5,245.675	4,669.104	4,789.644	3,719.734	3,832.790	4,900.097	5,571.000
10286	Okanogan County PUD #1	26,955.703	34,461.979	39,180.388	41,338.367	32,942.948	36,013.407	27,910.753	36,121.109	36,892.401	32,837.428	33,685.178	26,160.578	26,955.703	34,461.979	39,180.388
10288	Orcas P & L	14,522.271	18,566.246	21,108.269	22,270.871	17,747.874	19,402.071	15,036.801	19,460.096	19,875.626	17,691.025	18,147.748	14,093.901	14,522.271	18,566.246	21,108.269
10291	Oregon Trail Coop	46,489.861	59,435.758	67,573.486	71,295.303	56,815.921	62,111.469	48,137.014	62,297.221	63,627.449	56,633.932	58,096.028	45,118.530	46,489.861	59,435.758	67,573.486
10294	Pacific County PUD #2	21,328.328	27,267.565	31,000.942	32,708.413	26,065.653	28,495.112	22,083.998	28,580.330	29,190.602	25,982.161	26,652.932	20,699.197	21,328.328	27,267.565	31,000.942
10304	Parkland L & W	7,935.765	10,145.614	11,534.715	12,170.025	9,698.411	10,602.355	8,216.932	10,634.063	10,861.131	9,667.346	9,916.924	7,701.680	7,955.686	10,171.083	11,563.671

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10306	Pend Oreille County PUD #1	8,914.818	11,397.301	12,957.778	13,671.467	10,894.926	11,910.391	9,230.672	11,946.011	12,201.093	10,860.028	11,140.396	8,651.854	9,012.764	11,522.523	13,100.145
10307	Peninsula Light Company	40,713.491	52,050.859	59,177.473	62,436.853	49,756.537	54,394.113	42,155.985	54,556.785	55,721.731	49,597.160	50,877.590	39,512.548	40,759.560	52,109.755	59,244.434
10326	U.S. Naval Base, Bremerton	16,959.320	21,681.933	24,650.544	26,008.248	20,726.227	22,658.022	17,560.195	22,725.783	23,211.045	20,659.838	21,193.204	16,459.064	16,995.843	21,728.625	24,703.630
10331	Raft River Elec Coop	21,490.189	27,474.500	31,236.209	32,956.638	26,263.466	28,711.362	22,251.594	28,797.227	29,412.131	26,179.340	26,855.203	20,856.283	21,490.189	27,474.500	31,236.209
10333	Ravalli County Elec Coop	10,870.849	13,898.022	15,800.888	16,671.171	13,285.419	14,523.691	11,256.007	14,567.126	14,878.176	13,242.863	13,584.750	10,550.186	10,870.849	13,898.022	15,800.888
10338	Riverside Elec Coop	1,392.837	1,780.696	2,024.502	2,136.008	1,702.205	1,860.860	1,442.185	1,866.425	1,906.279	1,696.753	1,740.558	1,351.751	1,392.837	1,780.696	2,024.502
10342	Salem Elec Coop	22,716.599	29,042.424	33,018.808	34,837.420	27,762.279	30,349.872	23,521.457	30,440.637	31,090.633	27,673.353	28,387.785	22,046.518	22,716.599	29,042.424	33,018.808
10343	Salmon River Elec Coop	6,866.236	8,778.256	9,980.144	10,529.830	8,391.324	9,173.441	7,109.509	9,200.875	9,397.341	8,364.446	8,580.388	6,663.699	6,899.023	8,820.174	10,027.800
10349	Seattle City Light	299,962.867	383,492.653	435,999.072	460,013.055	366,588.887	400,756.934	310,590.656	401,955.448	410,538.366	365,414.652	374,848.418	291,114.730	307,602.302	393,259.418	447,103.068
10352	Skamania County PUD #1	9,338.977	11,939.575	13,574.298	14,321.944	11,413.296	12,477.077	9,669.861	12,514.392	12,781.611	11,376.738	11,670.448	9,063.502	9,338.977	11,939.575	13,574.298
10354	Snohomish County PUD #1	456,183.013	583,214.968	663,066.640	699,587.064	557,507.750	609,470.458	472,345.736	611,293.155	624,346.043	555,721.975	570,068.830	442,726.781	460,349.902	588,542.198	669,123.256
10360	Southside Elec Lines	3,971.825	5,077.847	5,773.088	6,091.059	4,854.024	5,306.445	4,112.549	5,322.315	5,435.961	4,838.476	4,963.389	3,854.667	3,971.825	5,077.847	5,773.088
10363	Springfield Utility Board	52,562.147	67,198.975	76,399.615	80,607.557	64,236.948	70,224.176	54,424.443	70,434.190	71,938.165	64,031.188	65,684.256	51,011.698	52,675.865	67,344.361	76,564.905
10369	Surprise Valley Elec Coop	9,647.759	12,334.342	14,023.115	14,795.481	11,790.663	12,889.615	9,989.582	12,928.164	13,204.217	11,752.896	12,056.316	9,363.175	9,647.759	12,334.342	14,023.115
10370	Tacoma Public Utilities	68,861.987	88,037.784	100,091.597	105,604.448	84,157.214	92,001.117	71,301.791	92,276.258	94,246.625	83,887.647	86,053.341	66,830.735	67,648.443	86,486.307	98,327.699
10371	Tanner Elec Coop	6,477.354	8,281.084	9,414.900	9,933.454	7,916.066	8,653.886	6,706.849	8,679.767	8,865.105	7,890.710	8,094.421	6,286.288	6,477.354	8,281.084	9,414.900
10376	Tillamook PUD #1	32,598.849	41,676.556	47,382.758	49,992.508	39,839.517	43,552.773	33,753.837	43,683.023	44,615.783	39,711.906	40,737.132	31,637.267	32,896.010	42,056.465	47,814.684
10378	Coulee Dam, City of	1,186.982	1,517.517	1,725.291	1,820.316	1,450.628	1,585.834	1,229.037	1,590.577	1,624.541	1,445.982	1,483.311	1,151.970	1,186.982	1,517.517	1,725.291
10379	Steilacoom, Town of	2,698.932	3,450.496	3,922.925	4,138.993	3,298.403	3,605.833	2,794.556	3,616.616	3,693.841	3,287.838	3,372.719	2,619.320	2,705.158	3,458.455	3,931.973
10388	Umatilla Elec Coop	66,476.401	84,987.892	96,624.125	101,945.994	81,241.756	88,813.923	68,831.684	89,079.532	90,981.640	80,981.528	83,072.196	64,515.518	66,476.401	84,987.892	96,624.125
10391	United Electric Coop	17,600.540	22,501.711	25,582.563	26,991.601	21,509.870	23,514.705	18,224.133	23,585.029	24,088.637	21,440.971	21,994.504	17,081.369	17,600.540	22,501.711	25,582.563
10406	U.S. DOE Albany Research Center	268.939	343.829	390.905	412.435	328.674	359.307	278.467	360.383	368.077	327.621	336.079	261.005	268.939	343.829	390.905
10408	U.S. Naval Station, Everett (Jim Creek)	896.462	1,146.097	1,303.017	1,374.785	1,095.579	1,197.693	928.224	1,201.275	1,226.926	1,092.070	1,120.264	870.019	896.462	1,146.097	1,303.017
10409	U.S. Naval Submarine Base, Bangor	11,989.766	15,328.522	17,427.246	18,387.106	14,652.864	16,018.589	12,414.567	16,066.495	16,409.561	14,605.929	14,983.004	11,636.099	11,989.766	15,328.522	17,427.246
10426	U.S. DOE Richland Operations Office	24,160.900	30,888.915	35,118.113	37,052.349	29,527.378	32,279.488	25,016.929	32,376.024	33,067.346	29,432.799	30,192.653	23,448.215	24,649.804	31,513.962	35,828.739

PF System Shaped Loads (MWh), October 2026 through December 2027																
		Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
10434	Vera Irrigation District	15,944.160	20,384.083	23,174.998	24,451.432	19,485.585	21,301.745	16,509.067	21,365.451	21,821.666	19,423.170	19,924.610	15,473.848	15,944.160	20,384.083	23,174.998
10436	Vigilante Elec Coop	11,245.204	14,376.624	16,345.019	17,245.271	13,742.924	15,023.838	11,643.626	15,068.769	15,390.531	13,698.903	14,052.563	10,913.499	11,245.204	14,376.624	16,345.019
10440	Wahkiakum County PUD #1	2,938.819	3,757.183	4,271.603	4,506.875	3,591.572	3,926.326	3,042.942	3,938.068	4,022.157	3,580.067	3,672.493	2,852.131	2,938.819	3,757.183	4,271.603
10442	Wasco Elec Coop	7,665.997	9,800.724	11,142.603	11,756.316	9,368.723	10,241.938	7,937.605	10,272.568	10,491.917	9,338.714	9,579.808	7,439.869	7,673.466	9,810.274	11,153.462
10446	Wells Rural Elec Coop	53,005.813	67,766.188	77,044.487	81,287.948	64,779.158	70,816.923	54,883.828	71,028.710	72,545.379	64,571.662	66,238.683	51,442.277	55,130.346	70,482.332	80,132.517
10448	West Oregon Elec Coop	4,979.515	6,366.146	7,237.776	7,636.419	6,085.537	6,652.741	5,155.941	6,672.636	6,815.117	6,066.043	6,222.649	4,832.632	4,979.515	6,366.146	7,237.776
10451	Whatcom County PUD #1	15,754.077	20,141.069	22,898.710	24,159.927	19,253.281	21,047.791	16,312.249	21,110.736	21,561.512	19,191.611	19,687.073	15,289.372	15,754.077	20,141.069	22,898.710
10482	Umpqua Indian Utility Cooperative	1,569.638	2,006.732	2,281.486	2,407.146	1,918.278	2,097.072	1,625.252	2,103.343	2,148.256	1,912.133	1,961.498	1,523.338	1,570.469	2,007.793	2,282.692
10502	Yakama Power	10,983.321	14,041.815	15,964.368	16,843.655	13,422.873	14,673.957	11,372.464	14,717.841	15,032.109	13,379.878	13,725.301	10,659.342	10,983.321	14,041.815	15,964.368
13927	Kalispel Tribe Utility	2,391.810	3,057.852	3,476.522	3,668.001	2,923.066	3,195.511	2,476.553	3,205.068	3,273.505	2,913.703	2,988.925	2,321.259	2,391.810	3,057.852	3,476.522
10597	Hermiston, City of	7,595.856	9,711.053	11,040.655	11,648.753	9,283.004	10,148.230	7,864.980	10,178.580	10,395.921	9,253.269	9,492.158	7,371.798	7,595.856	9,711.053	11,040.655
10706	Port of Seattle - SETAC In'tl. Airport	9,825.806	12,561.969	14,281.908	15,068.528	12,008.257	13,127.491	10,173.938	13,166.751	13,447.899	11,969.793	12,278.812	9,535.970	9,824.560	12,560.377	14,280.099
11680	Weiser, City of	3,715.752	4,750.467	5,400.884	5,698.354	4,541.074	4,964.326	3,847.403	4,979.172	5,085.492	4,526.528	4,643.388	3,606.147	3,715.752	4,750.467	5,400.884
12026	Jefferson County PUD #1	26,521.997	33,907.501	38,549.993	40,673.252	32,412.911	35,433.968	27,461.681	35,539.938	36,298.819	32,309.088	33,143.199	25,739.667	26,521.997	33,907.501	38,549.993
10298	PNGC Aggregate	444,533.155	568,321.009	646,133.454	681,721.231	543,270.293	593,905.994	460,283.120	595,682.143	608,401.692	541,530.122	555,510.593	431,420.565	444,563.038	568,359.212	646,176.888

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10015	Asotin County PUD #1	516.817	425.712	450.244	348.943	451.590	461.233	410.537	421.136	327.063	3,813.275
10024	Benton County PUD #1	180,910.812	149,019.537	157,606.967	122,146.984	158,078.310	161,453.742	143,707.793	147,417.841	114,487.625	1,334,829.611
10025	Benton REA	53,717.156	44,247.801	46,797.635	36,268.637	46,937.588	47,939.842	42,670.606	43,772.216	33,994.373	396,345.854
10027	Big Bend Elec Coop	55,098.941	45,386.004	48,001.427	37,201.588	48,144.981	49,173.016	43,768.238	44,898.184	34,868.822	406,541.201
10029	Blachly Lane Elec Coop	15,861.575	13,065.469	13,818.383	10,709.385	13,859.708	14,155.653	12,599.756	12,925.039	10,037.842	117,032.810
10044	Canby, City of	18,285.906	15,062.434	15,930.425	12,346.240	15,978.067	16,319.246	14,525.540	14,900.540	11,572.056	134,920.454
10046	Central Electric Coop	73,698.629	60,706.906	64,205.214	49,759.687	64,397.228	65,772.296	58,543.032	60,054.414	46,639.452	543,776.858
10047	Central Lincoln PUD	136,054.650	112,070.699	118,528.907	91,861.095	118,883.382	121,421.889	108,075.982	110,866.137	86,100.845	1,003,863.586
10055	Albion, City of	358.335	295.167	312.177	241.940	313.110	319.796	284.646	291.994	226.769	2,643.934

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10057	Ashland, City of	17,208.992	14,175.360	14,992.232	11,619.131	15,037.069	15,358.153	13,670.085	14,023.000	10,890.541	126,974.563
10059	Bandon, City of	6,878.377	5,665.845	5,992.346	4,644.128	6,010.267	6,138.604	5,463.888	5,604.947	4,352.913	50,751.315
10061	Blaine, City of	7,875.096	6,486.860	6,860.674	5,317.091	6,881.191	7,028.124	6,255.639	6,417.139	4,983.677	58,105.491
10062	Bonniers Ferry, City of	4,789.469	3,945.173	4,172.518	3,233.743	4,184.997	4,274.359	3,804.549	3,902.770	3,030.968	35,338.546
10064	Burley, City of	12,663.292	10,430.985	11,032.083	8,549.976	11,065.076	11,301.348	10,059.177	10,318.871	8,013.840	93,434.648
10065	Cascade Locks, City of	2,140.463	1,763.139	1,864.742	1,445.193	1,870.318	1,910.254	1,700.293	1,744.188	1,354.571	15,793.161
10066	Centralia, City of	21,944.360	18,075.970	19,117.619	14,816.347	19,174.793	19,584.231	17,431.659	17,881.686	13,887.272	161,913.937
10067	Cheney, City of	14,241.748	11,731.189	12,407.212	9,615.714	12,444.317	12,710.040	11,313.035	11,605.098	9,012.750	105,081.103
10068	Chewelah, City of	2,255.029	1,857.508	1,964.549	1,522.545	1,970.424	2,012.499	1,791.298	1,837.543	1,427.073	16,638.468
10070	Declo, City of	323.329	266.332	281.679	218.304	282.522	288.555	256.839	263.469	204.616	2,385.645
10071	Drain, City of	1,701.932	1,401.913	1,482.700	1,149.107	1,487.134	1,518.889	1,351.942	1,386.845	1,077.051	12,557.513
10072	Ellensburg, City of	21,593.027	17,786.570	18,811.542	14,579.134	18,867.800	19,270.683	17,152.574	17,595.395	13,664.934	159,321.659
10074	Forest Grove, City of	24,024.358	19,789.303	20,929.684	16,220.716	20,992.277	21,440.524	19,083.920	19,576.602	15,203.578	177,260.962
10076	Heyburn, City of	4,337.572	3,572.938	3,778.832	2,928.633	3,790.133	3,871.064	3,445.582	3,534.535	2,744.990	32,004.279
10078	McCleary, City of	3,347.218	2,757.165	2,916.050	2,259.968	2,924.770	2,987.222	2,658.887	2,727.530	2,118.254	24,697.064
10079	McMinnville, City of	75,697.795	62,353.656	65,946.859	51,109.480	66,144.082	67,556.451	60,131.084	61,683.464	47,904.604	558,527.475
10080	Milton, Town of	5,971.401	4,918.753	5,202.201	4,031.759	5,217.759	5,329.174	4,743.426	4,865.884	3,778.943	44,059.300
10081	Milton-Freewater, City of	8,363.909	6,889.504	7,286.520	5,647.127	7,308.311	7,464.365	6,643.930	6,815.454	5,293.017	61,712.137
10082	Minidoka, City of	103.108	84.933	89.827	69.617	90.095	92.019	81.906	84.020	65.251	760.776
10083	Monmouth, City of	7,530.128	6,202.703	6,560.141	5,084.176	6,579.760	6,720.258	5,981.611	6,136.035	4,765.366	55,560.178
10086	Plummer, City of	2,296.399	1,891.586	2,000.591	1,550.478	2,006.574	2,049.420	1,824.162	1,871.255	1,453.254	16,943.719
10087	Port Angeles, City of	43,758.243	36,044.464	38,121.568	29,544.600	38,235.576	39,052.017	34,759.672	35,657.049	27,691.973	322,865.162
10089	Richland, City of	93,833.493	77,292.361	81,746.425	63,354.302	81,990.899	83,741.643	74,537.304	76,461.604	59,381.602	692,339.633
10091	Rupert, City of	8,465.108	6,972.864	7,374.684	5,715.454	7,396.739	7,554.680	6,724.319	6,897.918	5,357.060	62,458.826
10094	Soda Springs, City of	2,510.255	2,067.743	2,186.898	1,694.869	2,193.439	2,240.275	1,994.039	2,045.518	1,588.590	18,521.626
10095	Sumas, Town of	3,280.389	2,702.116	2,857.829	2,214.846	2,866.375	2,927.581	2,605.800	2,673.073	2,075.962	24,203.971
10097	Troy, City of	1,799.313	1,482.127	1,567.536	1,214.856	1,572.224	1,605.796	1,429.297	1,466.197	1,138.677	13,276.023
10101	Clallam County PUD #1	68,455.354	56,387.925	59,637.346	46,219.543	59,815.700	61,092.938	54,377.999	55,781.854	43,321.296	505,089.955

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10103	Clark County PUD #1	286,771.122	236,218.607	249,830.987	193,621.529	250,578.138	255,928.711	227,798.687	233,679.676	181,480.280	2,115,907.737
10105	Clatskanie PUD	31,671.597	26,088.472	27,591.851	21,383.963	27,674.368	28,265.297	25,158.559	25,808.067	20,043.058	233,685.232
10106	Clearwater Power	21,500.101	17,710.026	18,730.587	14,516.394	18,786.603	19,187.752	17,078.758	17,519.674	13,606.127	158,636.022
10109	Columbia Basin Elec Coop	10,911.079	8,987.654	9,505.579	7,366.919	9,534.006	9,737.585	8,667.293	8,891.053	6,904.968	80,506.136
10111	Columbia Power Coop	2,880.047	2,372.347	2,509.056	1,944.543	2,516.560	2,570.296	2,287.785	2,346.848	1,822.609	21,250.091
10112	Columbia River PUD	52,448.663	43,202.921	45,692.541	35,412.179	45,829.189	46,807.776	41,662.970	42,738.565	33,191.619	386,986.423
10113	Columbia REA	33,938.718	27,955.942	29,566.936	22,914.672	29,655.360	30,288.588	26,959.462	27,655.465	21,477.783	250,412.926
10116	Consolidated Irrigation District #19	204.944	168.817	178.545	138.374	179.079	182.903	162.799	167.002	129.697	1,512.160
10118	Consumers Power	41,124.513	33,875.011	35,827.100	27,766.362	35,934.244	36,701.545	32,667.550	33,510.915	26,025.243	303,432.483
10121	Coos Curry Elec Coop	35,976.072	29,634.147	31,341.850	24,290.250	31,435.582	32,106.823	28,577.849	29,315.633	22,767.102	265,445.308
10123	Cowlitz County PUD #1	158,520.283	130,576.050	138,100.652	107,029.394	138,513.659	141,471.328	125,921.717	129,172.588	100,317.999	1,169,623.670
10136	Douglas Electric Cooperative	16,633.619	13,701.415	14,490.976	11,230.652	14,534.313	14,844.663	13,213.033	13,554.149	10,526.422	122,729.242
10142	East End Mutual Electric	2,419.239	1,992.771	2,107.607	1,633.417	2,113.910	2,159.048	1,921.739	1,971.352	1,530.992	17,850.075
10144	Eatonville, City of	2,970.425	2,446.793	2,587.793	2,005.566	2,595.532	2,650.955	2,359.579	2,420.495	1,879.805	21,916.943
10156	Elmhurst Mutual P & L	29,027.046	23,910.107	25,287.956	19,598.421	25,363.582	25,905.169	23,057.841	23,653.116	18,369.480	214,172.718
10157	Emerald PUD	44,982.183	37,052.645	39,187.848	30,370.977	39,305.044	40,144.321	35,731.918	36,654.395	28,466.531	331,895.862
10158	Energy Northwest	2,029.717	1,671.914	1,768.260	1,370.420	1,773.548	1,811.419	1,612.320	1,653.944	1,284.486	14,976.028
10170	Eugene Water & Electric Board	112,056.388	92,302.892	97,621.956	75,657.999	97,913.907	100,004.654	89,012.791	91,310.799	70,913.781	826,795.167
10172	U.S. Airforce Base, Fairchild	4,731.549	3,897.464	4,122.060	3,194.638	4,134.388	4,222.668	3,758.540	3,855.573	2,994.315	34,911.195
10173	Fall River Elec Coop	29,830.277	24,571.743	25,987.719	20,140.744	26,065.439	26,622.012	23,695.893	24,307.640	18,877.796	220,099.263
10174	Farmers Elec Coop	456.352	375.906	397.567	308.119	398.756	407.271	362.506	371.865	288.798	3,367.140
10177	Ferry County PUD #1	8,728.608	7,189.914	7,604.241	5,893.364	7,626.983	7,789.841	6,933.632	7,112.635	5,523.814	64,403.032
10179	Flathead Elec Coop	150,206.656	123,727.964	130,857.936	101,416.216	131,249.283	134,051.837	119,317.728	122,398.107	95,056.803	1,108,282.530
10183	Franklin County PUD #1	56,133.212	46,237.952	48,902.469	37,899.905	49,048.718	50,096.051	44,589.818	45,740.976	35,523.350	414,172.451
10186	Glacier Elec Coop	16,552.150	13,634.308	14,420.001	11,175.646	14,463.126	14,771.956	13,148.318	13,487.763	10,474.865	122,128.133
10190	Grant County PUD #2	4,674.267	3,850.280	4,072.156	3,155.962	4,084.334	4,171.547	3,713.037	3,808.896	2,958.063	34,488.542
10191	Grays Harbor PUD #1	114,107.108	93,992.108	99,408.515	77,042.599	99,705.809	101,834.818	90,641.796	92,981.859	72,211.560	841,926.172

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10197	Harney Elec Coop	20,486.834	16,875.379	17,847.843	13,832.258	17,901.219	18,283.462	16,273.863	16,693.999	12,964.891	151,159.748
10202	Hood River Elec Coop	11,793.868	9,714.825	10,274.653	7,962.960	10,305.381	10,525.431	9,368.544	9,610.408	7,463.633	87,019.703
10203	Idaho County L & P	5,594.609	4,608.381	4,873.945	3,777.356	4,888.521	4,992.905	4,444.117	4,558.849	3,540.493	41,279.176
10204	Idaho Falls Power	36,729.021	30,254.365	31,997.809	24,798.624	32,093.502	32,778.792	29,175.960	29,929.184	23,243.599	271,000.856
10209	Inland P & L	94,443.235	77,794.616	82,277.624	63,765.987	82,523.686	84,285.807	75,021.658	76,958.462	59,767.471	696,838.546
10230	Kittitas County PUD #1	8,735.610	7,195.681	7,610.341	5,898.091	7,633.100	7,796.089	6,939.193	7,118.340	5,528.245	64,454.690
10231	Klickitat County PUD #1	33,007.556	27,188.927	28,755.721	22,285.973	28,841.718	29,457.572	26,219.788	26,896.693	20,888.507	243,542.455
10234	Kootenai Electric Coop	45,919.710	37,824.903	40,004.608	31,003.974	40,124.247	40,981.016	36,476.649	37,418.352	29,059.836	338,813.295
10235	Lakeview L & P (WA)	27,406.582	22,575.302	23,876.231	18,504.319	23,947.636	24,458.987	21,770.614	22,332.658	17,343.986	202,216.315
10236	Lane County Elec Coop	26,204.282	21,584.946	22,828.804	17,692.553	22,897.076	23,385.996	20,815.559	21,352.946	16,583.122	193,345.284
10237	Lewis County PUD #1	41,332.003	34,045.925	36,007.862	27,906.455	36,115.549	36,886.721	32,832.371	33,679.992	26,156.551	304,963.429
10239	Lincoln Elec Coop (MT)	12,606.010	10,383.800	10,982.179	8,511.299	11,015.023	11,250.225	10,013.674	10,272.193	7,977.589	93,011.992
10242	Lost River Elec Coop	8,577.127	7,065.136	7,472.273	5,791.087	7,494.620	7,654.652	6,813.302	6,989.199	5,427.950	63,285.346
10244	Lower Valley Energy	77,467.830	63,811.665	67,488.889	52,304.568	67,690.723	69,136.117	61,537.123	63,125.803	49,024.753	571,587.471
10246	Mason County PUD #1	8,092.134	6,665.638	7,049.754	5,463.630	7,070.837	7,221.820	6,428.044	6,593.994	5,121.027	59,706.878
10247	Mason County PUD #3	71,967.420	59,280.877	62,697.008	48,590.812	62,884.511	64,227.278	57,167.832	58,643.712	45,543.872	531,003.322
10256	Midstate Elec Coop	42,089.407	34,669.813	36,667.702	28,417.838	36,777.362	37,562.666	33,434.021	34,297.173	26,635.867	310,551.849
10258	Mission Valley	34,172.304	28,148.351	29,770.433	23,072.385	29,859.464	30,497.052	27,145.013	27,845.806	21,625.606	252,136.414
10259	Missoula Elec Coop	24,297.406	20,014.216	21,167.560	16,405.072	21,230.864	21,684.204	19,300.817	19,799.099	15,376.373	179,275.611
10260	Modern Elec Coop	23,666.660	19,494.659	20,618.062	15,979.206	20,679.724	21,121.295	18,799.780	19,285.126	14,977.212	174,621.724
10273	Nespelem Valley Elec Coop	5,295.466	4,361.972	4,613.336	3,575.381	4,627.133	4,725.935	4,206.491	4,315.088	3,351.183	39,071.985
10278	Northern Lights	32,349.442	26,646.826	28,182.380	21,841.629	28,266.664	28,870.239	25,697.010	26,360.419	20,472.025	238,686.634
10279	Northern Wasco County PUD	58,313.773	48,034.119	50,802.143	39,372.172	50,954.073	52,042.090	46,321.961	47,517.838	36,903.297	430,261.466
10284	Ohop Mutual Light Company	9,640.039	7,940.676	8,398.267	6,508.741	8,423.383	8,603.247	7,657.634	7,855.328	6,100.604	71,127.919
10285	Okanogan County Elec Coop	5,877.839	4,841.684	5,120.692	3,968.588	5,136.006	5,245.675	4,669.104	4,789.644	3,719.734	43,368.966
10286	Okanogan County PUD #1	41,338.367	34,051.168	36,013.407	27,910.753	36,121.109	36,892.401	32,837.428	33,685.178	26,160.578	305,010.389
10288	Orcas P & L	22,270.871	18,344.924	19,402.071	15,036.801	19,460.096	19,875.626	17,691.025	18,147.748	14,093.901	164,323.063

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10291	Oregon Trail Coop	71,295.303	58,727.242	62,111.469	48,137.014	62,297.221	63,627.449	56,633.932	58,096.028	45,118.530	526,044.188
10294	Pacific County PUD #2	32,708.413	26,942.517	28,495.112	22,083.998	28,580.330	29,190.602	25,982.161	26,652.932	20,699.197	241,335.262
10304	Parkland L & W	12,200.575	10,049.837	10,628.971	8,237.559	10,660.758	10,888.396	9,691.614	9,941.819	7,721.014	90,020.543
10306	Pend Oreille County PUD #1	13,821.676	11,385.167	12,041.250	9,332.090	12,077.261	12,335.145	10,979.346	11,262.796	8,746.911	101,981.642
10307	Peninsula Light Company	62,507.502	51,488.570	54,455.661	42,203.685	54,618.517	55,784.782	49,653.280	50,935.160	39,557.257	461,204.414
10326	U.S. Naval Base, Bremerton	26,064.259	21,469.605	22,706.817	17,598.012	22,774.725	23,261.031	20,704.329	21,238.845	16,494.509	192,312.132
10331	Raft River Elec Coop	32,956.638	27,146.985	28,711.362	22,251.594	28,797.227	29,412.131	26,179.340	26,855.203	20,856.283	243,166.763
10333	Ravalli County Elec Coop	16,671.171	13,732.347	14,523.691	11,256.007	14,567.126	14,878.176	13,242.863	13,584.750	10,550.186	123,006.317
10338	Riverside Elec Coop	2,136.008	1,759.469	1,860.860	1,442.185	1,866.425	1,906.279	1,696.753	1,740.558	1,351.751	15,760.288
10342	Salem Elec Coop	34,837.420	28,696.218	30,349.872	23,521.457	30,440.637	31,090.633	27,673.353	28,387.785	22,046.518	257,043.893
10343	Salmon River Elec Coop	10,580.112	8,715.032	9,217.245	7,143.458	9,244.811	9,442.215	8,404.387	8,621.360	6,695.520	78,064.140
10349	Seattle City Light	471,728.637	388,571.489	410,963.385	318,500.758	412,192.423	420,993.930	374,721.008	384,395.032	298,528.821	3,480,595.483
10352	Skamania County PUD #1	14,321.944	11,797.247	12,477.077	9,669.861	12,514.392	12,781.611	11,376.738	11,670.448	9,063.502	105,672.820
10354	Snohomish County PUD #1	705,977.265	581,526.359	615,037.512	476,660.258	616,876.858	630,048.975	560,798.077	575,275.980	446,770.758	5,208,972.042
10360	Southside Elec Lines	6,091.059	5,017.317	5,306.445	4,112.549	5,322.315	5,435.961	4,838.476	4,963.389	3,854.667	44,942.178
10363	Springfield Utility Board	80,781.951	66,541.568	70,376.106	54,542.190	70,586.574	72,093.803	64,169.719	65,826.364	51,122.062	596,040.337
10369	Surprise Valley Elec Coop	14,795.481	12,187.308	12,889.615	9,989.582	12,928.164	13,204.217	11,752.896	12,056.316	9,363.175	109,166.754
10370	Tacoma Public Utilities	103,743.397	85,455.330	90,379.796	70,045.251	90,650.087	92,585.731	82,409.307	84,536.837	65,652.987	765,458.723
10371	Tanner Elec Coop	9,933.454	8,182.367	8,653.886	6,706.849	8,679.767	8,865.105	7,890.710	8,094.421	6,286.288	73,292.847
10376	Tillamook PUD #1	50,448.224	41,555.123	43,949.787	34,061.527	44,081.224	45,022.486	40,073.907	41,108.478	31,925.661	372,226.417
10378	Coulee Dam, City of	1,820.316	1,499.428	1,585.834	1,229.037	1,590.577	1,624.541	1,445.982	1,483.311	1,151.970	13,430.996
10379	Steilacoom, Town of	4,148.539	3,417.227	3,614.150	2,801.002	3,624.958	3,702.361	3,295.422	3,380.499	2,625.363	30,609.521
10388	Umatilla Elec Coop	101,945.994	83,974.776	88,813.923	68,831.684	89,079.532	90,981.640	80,981.528	83,072.196	64,515.518	752,196.791
10391	United Electric Coop	26,991.601	22,233.474	23,514.705	18,224.133	23,585.029	24,088.637	21,440.971	21,994.504	17,081.369	199,154.423
10406	U.S. DOE Albany Research Center	412.435	339.730	359.307	278.467	360.383	368.077	327.621	336.079	261.005	3,043.104
10408	U.S. Naval Station, Everett (Jim Creek)	1,374.785	1,132.435	1,197.693	928.224	1,201.275	1,226.926	1,092.070	1,120.264	870.019	10,143.691

PF System Shaped Loads (MWh), January 2028 through September 2028											
		Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Total (October 2026 -- September 2028)
10409	U.S. Naval Submarine Base, Bangor	18,387.106	15,145.794	16,018.589	12,414.567	16,066.495	16,409.561	14,605.929	14,983.004	11,636.099	135,667.144
10426	U.S. DOE Richland Operations Office	37,802.117	31,138.294	32,932.675	25,523.154	33,031.164	33,736.476	30,028.381	30,803.612	23,922.697	278,918.570
10434	Vera Irrigation District	24,451.432	20,141.091	21,301.745	16,509.067	21,365.451	21,821.666	19,423.170	19,924.610	15,473.848	180,412.080
10436	Vigilante Elec Coop	17,245.271	14,205.244	15,023.838	11,643.626	15,068.769	15,390.531	13,698.903	14,052.563	10,913.499	127,242.244
10440	Wahkiakum County PUD #1	4,506.875	3,712.395	3,926.326	3,042.942	3,938.068	4,022.157	3,580.067	3,672.493	2,852.131	33,253.454
10442	Wasco Elec Coop	11,767.773	9,693.330	10,251.919	7,945.340	10,282.578	10,502.142	9,347.815	9,589.143	7,447.120	86,827.160
10446	Wells Rural Elec Coop	84,546.061	69,642.133	73,655.344	57,083.632	73,875.619	75,453.079	67,159.766	68,893.604	53,504.142	623,813.380
10448	West Oregon Elec Coop	7,636.419	6,290.257	6,652.741	5,155.941	6,672.636	6,815.117	6,066.043	6,222.649	4,832.632	56,344.435
10451	Whatcom County PUD #1	24,159.927	19,900.973	21,047.791	16,312.249	21,110.736	21,561.512	19,191.611	19,687.073	15,289.372	178,261.244
10482	Umpqua Indian Utility Cooperative	2,408.419	1,983.858	2,098.181	1,626.111	2,104.456	2,149.391	1,913.144	1,962.535	1,524.144	17,770.239
10502	Yakama Power	16,843.655	13,874.426	14,673.957	11,372.464	14,717.841	15,032.109	13,379.878	13,725.301	10,659.342	124,278.973
13927	Kalispel Tribe Utility	3,668.001	3,021.399	3,195.511	2,476.553	3,205.068	3,273.505	2,913.703	2,988.925	2,321.259	27,063.924
10597	Hermiston, City of	11,648.753	9,595.290	10,148.230	7,864.980	10,178.580	10,395.921	9,253.269	9,492.158	7,371.798	85,948.979
10706	Port of Seattle - SETAC In'tl. Airport	15,066.619	12,410.649	13,125.828	10,172.649	13,165.082	13,446.194	11,968.276	12,277.256	9,534.762	111,167.315
11680	Weiser, City of	5,698.354	4,693.839	4,964.326	3,847.403	4,979.172	5,085.492	4,526.528	4,643.388	3,606.147	42,044.649
12026	Jefferson County PUD #1	40,673.252	33,503.300	35,433.968	27,461.681	35,539.938	36,298.819	32,309.088	33,143.199	25,739.667	300,102.912
10298	PNGC Aggregate	681,767.057	561,583.969	593,945.917	460,314.060	595,722.186	608,442.588	541,566.525	555,547.935	431,449.565	5,030,339.802

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