BP-26 Rate Proceeding

APPENDIX E:

2026 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions FY 2026-2028

BP-26-A-01-AP02

July 2025

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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
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
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
MO	market operator
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement

NUG	non-utility generation
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	point of receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
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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TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES

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NT-26
NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-24 rate schedule. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, including Conditional Firm (CF) Service. Terms and conditions of service are specified in the Open Access Transmission Tariff (OATT). This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to Sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

$2.399 per kilowatt per month

SECTION III. BILLING FACTOR

The monthly Billing Factor will be the customer's Network Load on the hour of the Monthly Transmission System Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. Delivery Charge

Customers taking NT Service over DSI Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. Failure To Comply Penalty

Customers taking NT Service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. Short-Distance Discount (SDD)

A Customer's monthly NT bill will be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that i) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and ii) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load.

A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

Except as provided below, the NT monthly bill will be reduced by a credit equal to:

$$\textit{Avg. Generation of the DNR SD during HLH} \;*\; \textit{NT Rate} \;*\; \frac{\textit{75–Tx Distance}}{\textit{75}} \;*\; \textit{0.4}$$

Where:

Average Generation during HLH = The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's Point(s) of Delivery (POD) to the total DNR SD designated capacity.

The output serving Network Load is:

1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load.
2. in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = $2.399 per kilowatt per month

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD Point of Receipt (POR) and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD.

1. BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's

designated capacity is fully allocated to the qualifying PODs, subject to Section 2 below. The Tx Distance will be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD.

2. The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load.

3. For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Tx Distance will be zero.

Qualifying Capacity = The sum of all DNR SD designated capacity allocated to the Customer's POD(s). For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity will be the total DNR SD designated capacity.

Behind the Meter Resource = A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

Notwithstanding the formula above, the amount of the credit given for a particular DNR SD will be limited to the amount of the monthly charges for NT Service for that DNR SD.

E. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also will be recovered from the Network Customer under an applicable rate schedule.

F. Incremental Cost Rates

The rates specified in Section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades will be subject to the higher of the rates specified in Section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to Section 7(i) of the Northwest Power Act.

G. Rate Adjustment Due To FERC Order Under FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

H. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

I. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

J. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

K. Real Power Loss Imbalance Settlement

Customers taking service under this rate schedule are subject to the Real Power Loss Imbalance Settlement, specified in GRSP II.J.

L. Invalid Loss Return Penalty Charge

Customers taking service under this rate schedule are subject to the Invalid Loss Return Penalty Charge, specified in GRSP II.K.

PTP-26
POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-24 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, including Conditional Firm (CF) Transmission Service. Terms and conditions of PTP service are specified in the Open Access Transmission Tariff (OATT). This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to Sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. Long-Term Firm PTP Transmission Service

$2.043 per kilowatt per month

B. Short-Term Firm And Non-Firm PTP Transmission Service

For each reservation, the rates will not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 $0.094 per kilowatt per day
b. Day 6 and beyond $0.067 per kilowatt per day

2. Hourly Firm and Non-Firm Service

5.88 mills per kilowatthour

SECTION III. BILLING FACTORS

A. All Firm And Non-Firm Service

The Billing Factor for each rate specified in Sections II.A. and II.B. for all service will be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. Redirect Service

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

B. Delivery Charge

Customers taking PTP Transmission Service over DSI Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. Failure To Comply Penalty

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. Interruption of Non-Firm PTP Transmission Service

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under Section II.B.1. will be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under Section II.B.2 will apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

E. Reservation Fee

Customers that postpone the commencement of Long-Term Firm Point-to-Point Transmission Service by requesting an extension of the Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

F. Short-Distance Discount (SDD)

Reservations for Long-Term Firm PTP Transmission Service that use BPA transmission facilities for a distance of less than 75 circuit miles will receive a SDD. The SDD will be designated in the PTP Service Agreement.

For reservations receiving a SDD, BPA will multiply the billing factors in Section III.A. by the following factor to calculate the customer's monthly transmission bill:

*0.6 + (0.4 * transmission distance / 75).*

System sales do not qualify for SDD. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD will be between the POR and the POD farthest from the POR.

If the customer redirects in the short term, on a firm or non-firm basis, any portion of Reserved Capacity from a reservation receiving a SDD for any period of time during a month, the SDD will not be applied to the entire reservation for that month.

G. Unauthorized Increase Charge

Customers that exceed their capacity reservations at any POR or POD will be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

H. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also will be recovered from the PTP Transmission Customer under an applicable rate schedule.

I. Incremental Cost Rates

The rates specified in Section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to Section 7(i) of the Northwest Power Act.

J. Rate Adjustment Due To FERC Order Under FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

K. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

L. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

M. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

N. Real Power Loss Imbalance Settlement

Customers taking service under this rate schedule are subject to the Real Power Loss Imbalance Settlement, specified in GRSP II.J.

O. Invalid Loss Return Penalty Charge

Customers taking service under this rate schedule are subject to the Invalid Loss Return Penalty Charge, specified in GRSP II.K.

IS-26
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-24 rate schedule. It is available to Transmission Customers taking Point-to-Point Transmission (PTP) Service over the Federal Columbia River Transmission System (FCRTS) Southern Intertie facilities. Terms and conditions of service are specified in the Open Access Transmission Tariff (OATT) or, for customers that executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to Sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. Long-Term Firm PTP Transmission Service

$1.187 per kilowatt per month

B. Short-Term Firm And Non-Firm PTP Transmission Service

For each reservation, the rates will not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 $0.055 per kilowatt per day

b. Day 6 and beyond $0.039 per kilowatt per day

2. Hourly Firm and Non-Firm Service

10.92 mills per kilowatthour

BPA intends to provide discounted service for Hourly Non-Firm Service in the south-to-north direction. BPA will post such discount on OASIS pursuant to Section II.E of the GRSPs. The following principles will apply to any such discount:

a. Providing a discount for service in one direction will not require the same discount to be provided in the other direction.

b. Providing a discount for service on the Southern Intertie will not require a discount to be provided for service on the Network or other segments.

SECTION III. BILLING FACTORS

A. All Firm Service And Monthly, Weekly, And Daily Non-Firm Service

The Billing Factor for each rate specified in Sections II.A. and II.B. for all services will be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Factor will be as specified in the agreement.

B. Redirect Service

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Southern Intertie are available under the ACS rate schedule.

B. Failure To Comply Penalty

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in GRSP II.B.

C. Interruption Of Non-Firm PTP Transmission Service

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under Section II.B.1 will be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under Section II.B.2 will apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. Reservation Fee

Customers that postpone the commencement of Long-Term Firm Point-to-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee specified in GRSP II.D.

E. Unauthorized Increase Charge

Customers that exceed their capacity reservations at any POR or POD will be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. Direct Assignment Facilities

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also will be recovered from the Transmission Customer under an applicable rate schedule.

G. Incremental Cost Rates

The rates specified in Section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than

embedded cost. Incremental cost rates would be developed pursuant to Section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due To FERC Order Under FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

I. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

J. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

L. Real Power Loss Imbalance Settlement

Customers taking service under this rate schedule are subject to the Real Power Loss Imbalance Settlement, specified in GRSP II.J.

M. Invalid Loss Return Penalty Charge

Customers taking service under this rate schedule are subject to the Invalid Loss Return Penalty Charge, specified in GRSP II.K.

IM-26
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-24 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie. Terms and conditions of service are specified in the Open Access Transmission Tariff (OATT). This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to Sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. Long-Term Firm PTP Transmission Service

$0.545 per kilowatt per month

B. Short-Term Firm And Non-Firm PTP Transmission Service

For each reservation, the rates will not exceed:

1. Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service

a. Days 1 through 5 $0.025 per kilowatt per day

b. Day 6 and beyond $0.018 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.57 mills per kilowatthour

SECTION III. BILLING FACTORS

A. All Firm Service And Monthly, Weekly, And Daily Non-Firm Service

The Billing Factor for each rate specified in Section II.A. and II.B. for all services will be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. Redirect Service

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Customers taking service under this rate schedule are subject to the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

B. Failure To Comply Penalty Charge

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

C. Interruption Of Non-Firm PTP Transmission Service

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under Section II.B.1 will be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under Section II.B.2 will apply as follows:

1. If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule for the hour.

2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. Reservation Fee

Customers that postpone the commencement of Long-Term Firm Point-to-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

E. Unauthorized Increase Charge

Customers that exceed their capacity reservations at any POR or POD will be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. Direct Assignment Facilities

BPA will collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also will be recovered from the Transmission Customer under an applicable rate schedule.

G. Incremental Cost Rates

The rates specified in Section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to Section 7(i) of the Northwest Power Act.

H. Rate Adjustment Due To FERC Order Under FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

I. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), specified in GRSP II.G.

J. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSP II.I.

UFT-26
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-24 rate schedule unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement will be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost will be determined in accordance with Section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once a year, BPA shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA and that are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA for making deliveries to the transferee will be determined from the costs specified in the agreement between BPA and such other entity.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand will be one-twelfth of the sum of the annual cost of the FCRTS facilities used, divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission Demand/capacity reservation for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with Section III.A.1., divided by 12.

For facilities used by more than one customer, BPA may charge a monthly amount equal to the annual cost of such facilities, prorated based on relative use of the facilities, divided by 12.

SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor will be the largest of:

A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Ancillary services that are required to support UFT transmission service are available under the ACS rate schedule.

B. Failure To Comply Penalty

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

AF-26
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-24 rate schedule and is available to customers that execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or;

C. Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

The charge is:

A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or

B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in the agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service will be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. Advance Payment

Payment to BPA shall be specified in the agreement as one of the following options:

1. A lump sum advance payment;

2. Advance payments pursuant to a schedule of progress payments; or

3. Other payment arrangement, as determined by BPA.

Such advance payment or payments will be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. Adjustment To Advance Payment

For charges under Section II.A., BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-26
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-24 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge will be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Columbia River Transmission System (FCRTS). Annual revenues plus credits for government use should equal the annual costs of the facilities, but in any given year there may be a surplus or a deficit. Such a surplus or deficit for any year will be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from non-firm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower the unit rate will be.

If BPA provides firm transmission service in its section of the Montana (Eastern) Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by BPA for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer.

A. Non-Firm Transmission Charge

This charge will be filed as a separate rate schedule, the Eastern intertie (IE) rate.

B. Intertie Charge For Firm Transmission Service

$$\textit{Intertie Charge} = [\ (\ (\textit{TAC} / 12) - \textit{NFR}) * \frac{(\textit{CR} - \textit{EC})}{\textit{TCR}}\ ]$$

SECTION III. DEFINITIONS

A. ***TAC*** = Total Annual Costs of facilities associated with the Townsend-Garrison 500 kV Transmission line including terminals, and prior to extension of the 500 kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: i) interest and amortization

of associated federal investment and the appropriate allocation of general plant costs; ii) operation and maintenance costs; iii) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and iv) payments made pursuant to Section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs will be adjusted to reflect reductions to unpaid total costs because of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. ***NFR*** = Non-firm Revenues, which are equal to a) the product of the Non-firm Transmission Charge described in II.A. above and the total non-firm energy transmitted over the Townsend-Garrison line segment under such charge during such month; plus b) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.

C. ***CR*** = Capacity Requirement of a customer on the Townsend-Garrison 500kV transmission facilities as specified in its firm transmission agreement.

D. ***TCR*** = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding a) the sum of all Capacity Requirements (CR) specified in transmission agreements described in Section I and b) BPA's firm capacity requirement. BPA's firm capacity requirement will be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. ***EC*** = Exchange Credit for each customer, which is the product of i) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and ii) the capacity BPA obtains in the Townsend-Broadview 500 kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer will be zero.

RC-26
REGIONAL COMPLIANCE ENFORCEMENT AND REGIONAL COORDINATOR RATES

SECTION I. AVAILABILITY

This schedule supersedes the RC-24 rate schedule. The rates in this schedule recover the costs billed to BPA by the "regional entity" and the "reliability coordinator" for reliability compliance monitoring and enforcement and reliability coordination services. The rates apply to all loads in the BPA Control Area except for loads of customers billed directly by the regional entity and the reliability coordinator. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. Regional Compliance Enforcement Rate

0.06 mills per kilowatthour

B. Regional Coordinator Rate

0.03 mills per kilowatthour

SECTION III. BILLING FACTORS

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

OS-26
OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-24 rate schedule. The Oversupply Rate applies to generators in the BPA balancing authority area (BAA) that are specified as the source on transmission schedules for the hours that BPA displaces generation pursuant to the Open Access Transmission Tariff (OATT), Attachment P (Oversupply Event Hours), and to customers that purchase power under the Priority Firm Power, Industrial Firm Power, or New Resource Firm Power rate, for the charges to BPA Power Services under Section II.C.

The Oversupply Charge will collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2025, through September 30, 2028. The Oversupply Charge will remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2026-2028 rate period are billed and fully paid. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

A. Oversupply Rate

For each month, the Oversupply rate in dollars per megawatthour ($/MWh) will be:

$$\frac{\textit{Displacement Cost}}{\sum \textit{Scheduled Generation}}$$

Where:

Displacement Cost = the amount BPA paid pursuant to OATT Attachment P to displace output from generating facilities for the calendar month, in dollars.

Scheduled Generation = For each generator in the BPA BAA, the sum of transmission schedules (e-Tags) during Oversupply Event Hours that specify such generator as the source, in megawatthours.

The after-the-fact schedule will be used for power dynamically transferred out of BPA's Balancing Authority Area.

$\sum$ *Scheduled Generation* = the sum of all Scheduled Generation, in megawatthours.

B. Oversupply Billing Factors

The billing factor for the monthly Oversupply Rate is the sum of the customer's Scheduled Generation during the month.

C. Oversupply Charges to BPA Power Services

Charges to BPA Power Services for its applicable Scheduled Generation under this rate schedule will be billed to customers purchasing under the Priority Firm Power, Industrial Firm Power, or New Resource Firm Power rate schedules using a Modified TOCA. The charge for each such customer will be the Oversupply Charge amount charged to BPA Power Services multiplied by each customer's Modified Tier 1 Cost Allocator (TOCA). The Modified TOCA for each customer for each fiscal year is specified in GRSP II.O.

SECTION III. BILLING

A. Oversupply Charge

The Oversupply charge will be included on bills for the month after Displacement Costs are incurred, subject to the billing cap; *i.e.,* there will be a one-month lag between Scheduled Generation and billing the Oversupply charge. Any Displacement Cost not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Cost for the month, will be included on the following month's bill, subject to the billing cap, and on subsequent bills as necessary until all Displacement Costs have been billed.

B. Billing Cap

Total billing to all customers for the Oversupply Charges may not exceed $8 million in any one month. If the total Oversupply Charges exceed $8 million in any month, the excess over $8 million will be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges will be billed in each subsequent month, subject to this billing cap, until all charges are billed.

C. Billing For Oversupply Charges To BPA Power Services

The charge for BPA Power Services costs (Section II.C) will be separately included on each applicable customer's transmission bill.

IE-26
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-24 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) for non-firm transmission service on the portion of Eastern Intertie capacity that exceeds BPA's firm transmission rights. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The rate will not exceed 1.54 mills per kilowatthour.

SECTION III. BILLING FACTOR

The Billing Factor will be the scheduled kilowatthours, unless otherwise specified in the Montana Intertie Agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Ancillary Services

Ancillary services that may be required to support IE transmission service are available under the ACS rate schedule.

B. Failure To Comply Penalty

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

ACS-26
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-24 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff (OATT) and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to Sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: a) Scheduling, System Control, and Dispatch, and b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: a) Regulation and Frequency Response, and b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self- supply.

The Transmission Provider is also required to offer to provide a) Operating Reserve – Spinning and b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. Control Area Services

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations.

Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area will be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

C. Energy Imbalance Market Services And Rates

EIM Service is used to meet the Energy Imbalance (EI) and Generation Imbalance (GI) obligations of loads and resources in the BPA Control Area or balancing authority area (BAA), and optimize the transmission system by economically dispatching generating resources across the EIM footprint. All Transmission Customers are subject to EIM charges and credits. The BPA BAA receives charges and credits from the California Independent System Operator (CAISO or Market Operator (MO)) for the BPA BAA on behalf of all loads, Interchange, and non-participating resources in the BAA in accordance with Section 29 of the Market Operator Tariff. This section allocates the charges and credits received by the BPA BAA.

1. EIM Imbalance Charges
   a. Energy Imbalance (EI) Service (Tariff Schedule 4E)
   b. Generator Imbalance (GI) Service (Tariff Schedule 9E)
2. Interchange and Intrachange Imbalance
3. Charges for Under-Scheduling or Over-Scheduling Load
4. EIM Neutrality and Uplift Charges and Credits
5. Flexible Ramping Product
6. Rolled In Charges
7. Other Charges and Provisions

SECTION II. ANCILLARY SERVICE RATES

A. Scheduling, System Control, And Dispatch Service

The rates below apply to Transmission Customers taking Scheduling, System Control, and Dispatch Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network and on the Southern Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. Rates

a. NT Service

The rate will not exceed $0.459 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate will not exceed $0.391 per kilowatt per month.

c. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates will not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(A) Days 1 through 5 $0.018 per kilowatt per day

(B) Day 6 and beyond $0.013 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate will not exceed 1.13 mills per kilowatthour.

2. Billing Factors

a. Point-to-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP and IS), the Billing Factor for each rate specified in Sections 1.b. and 1.c.(1) and for the Hourly Firm PTP Transmission Service rate specified in 1.c.(2) will be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service will not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control, and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in Section 1.b.(2) for Hourly Non-Firm Service will be the Reserved Capacity, and the following will apply:

(1) If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

(A) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

(B) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

(2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the OATT regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in Section 1.a. will equal the NT rate Billing Factor determined pursuant to Section III of the Network Integration Rate Schedule (NT-26).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a

billing month, the Billing Factor for the billing month will be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to Section II.F.2 of the GRSPs.

B. Reactive Supply And Voltage Control From Generation Sources Service

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, the Southern Intertie, and the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. Rates

The rates for GSR Service will be calculated for each quarter, beginning October 2025, according to the formulas below. The rates will be posted on BPA's website and updated as needed. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (Sections a. and b.(1), below) will be calculated to three decimal places. Rates for Hourly Service (Section b.(2), below) will be calculated to two decimal places.

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month ($/kW/mo), will not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

bd = 554,369 MW= Average of forecasted FY 2026, FY 2027, and FY 2028 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-federal GSR cost ($) to be paid by BPA under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter.

U_{q-1} = Payments of non-federal GSR cost ($) made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA would reduce this cost. U_{q-1} is a true-up for any deviation of non-federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2025, U_{q-1} is zero.

S_q = Reduction in effective billing demand (MW-mo) for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter.

Z_{q-1} = True-up ($) for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2025, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation.

"Relevant quarter" refers to the three-month period for which the rate is being determined.

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates will not exceed:

(A) Days 1 through 5 ($/kW/day)

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 5 \text{ days}}$$

(B) Day 6 and beyond ($/kW/day)

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 7 \text{ days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate will not exceed:

$$\text{Long-Term Service Rate} * \frac{12 \text{ months}}{52 \text{ weeks} * 5 \text{ days} * 16 \text{ hours}}$$

Where:

The "Long-Term Service Rate" specified in the formulas in Sections 1.b.(1)(a) and (b) and Section 1.b.(2), above, is the rate determined in Section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in $/kW/mo.

2. Billing Factors

a. Point-to-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in Sections 1.b. and 1.c.(1) and for Hourly Firm PTP Transmission Service specified in 1.c.(2) will be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service will not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in Section 1.b.(2) for Hourly Non-Firm Service will be the Reserved Capacity, and the following will apply:

(1) If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

(A) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

(B) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

(2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission services under the OATT regardless of whether the Transmission Customer uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in Section 1.a. will equal the NT rate Billing Factor determined pursuant to Section III of the Network Integration Rate Schedule (NT-26).

c. Adjustment for Self-Supply

The Billing Factors in Sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month will be the Billing Factor calculated above plus the UIC Billing Factor calculated pursuant to Section II.F.2 of the GRSPs.

C. Regulation And Frequency Response Service

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. RFR Service is the continuous balancing of resources with load by providing the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. Rate

The rate will not exceed 0.43 mills per kilowatthour.

2. Billing Factor

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. Energy Imbalance Service (Tariff Schedule 4)

The rates below apply to Transmission Customers taking EI Service from BPA when such services are provided pursuant to Schedule 4 of the BPA Tariff.

EI Service under Schedule 4 is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. Rates

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to a) ± 1.5 percent of the scheduled amount of energy, or b) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net EI (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greaterthan the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less thanthe energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation a) greater than ± 1.5 percent of the scheduled amount of energy or b) ± 2 MW,

whichever is larger in absolute value, up to and including ± 7.5 percent of the scheduled amount of energy or c) ± 10 MW, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation a) greater than ± 7.5 percent of the scheduled amount of energy, or b) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost will be determined separately for HLH and LLH.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost will be determined separately for HLH and LLH.

2. Other Rate Provisions

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS website at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

(2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

Transmission Customers taking EI Service will be subject to the Persistent Deviation Penalty Charge pursuant to GRSP II.M.2.

E. Operating Reserve – Spinning Reserve Service

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. Rates

a. For customers that elect to purchase Operating Reserve –Spinning Reserve Service from BPA, the rate will not exceed 13.14 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate will be 15.11 mills per kilowatthour.

Energy delivered will be settled as Generator Imbalance pursuant to ACS IV.A.2, except that the charges will not be less than zero.

If energy is provided through the NWPP Reserve Sharing Program or its successor, the generator will purchase the energy at the market index described in the NWPP Reserve Sharing Agreement.

2. Billing Factors

a. The Billing Factor for the rates specified in Sections 1.a. and 1.b. is the Transmission Customer's Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its Current Transmission Rates website the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. Operating Reserve – Supplemental Reserve Service

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. Rates

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate will not exceed 6.75 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate will be 7.76 mills per kilowatthour.

Energy delivered will be settled as Generator Imbalance pursuant to ACS IV.A.2, except that the charges will not be less than zero.

If energy is provided through the NWPP Reserve Sharing Program or its successor, the generator will purchase the energy at the market index described in the NWPP Reserve Sharing Agreement.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator will be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. Billing Factors

a. The Billing Factor for the rates specified in Sections 1.a. and 1.b. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its Current Transmission Rates website the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. Regulation And Frequency Response Service

The rate below applies to all loads in the BPA Control Area that are receiving RFR Service from the BPA Control Area, and such RFR Service is not provided for under a BPA transmission agreement. RFR Service is the continuous balancing of resources with load by providing the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. Rate

The rate will not exceed 0.43 mills per kilowatthour.

2. Billing Factor

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. Generation Imbalance Service (Schedule 9)

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance (GI) Service is provided for in an interconnection agreement or other arrangement. The rates below will apply when such services are provided pursuant to Schedule 9 of the BPA Tariff.

GI Service under Schedule 9 is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. Rates

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to a) ± 1.5 percent of the scheduled amount of energy, or b) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net GI (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour(HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancingtransaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incrementalcost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation a) greater than ± 1.5 percent of the scheduled amount of energy or b) ± 2 MW, whichever is larger in absolute value, up to and including c) ± 7.5 percent of the scheduled amount of energy or d) ± 10 MW, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5 percent of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost will be determined separately for HLH and LLH.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost will be determined separately for HLH and LLH.

2. Other Rate Provisions

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS website at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.

(2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. No Credit for Negative Deviations During Curtailments

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

d. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

(1) wind resources
(2) solar resources
(3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this Section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with Section 1.b., Imbalances Within Deviation Band 2.

C. Operating Reserve – Spinning Reserve Service

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. Rates

a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate will not exceed 13.14 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate will be 15.11 mills per kilowatthour.

Energy delivered will be settled as Generator Imbalance pursuant to ACS IV.A.2, except that the charges will not be less than zero.

If energy is provided through the NWPP Reserve Sharing Program or its successor, the generator shall purchase the energy at the market index described in the NWPP Reserve Sharing Agreement.

2. Billing Factors

a. The Billing Factor for the rates specified in Sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its Current Transmission Rates website the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. Operating Reserve – Supplemental Reserve Service

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. Rates

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate will not exceed 6.75 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate will be 7.76 mills per kilowatthour.

Energy delivered will be settled as Generator Imbalance pursuant to ACS IV.A.2, except that the charges will not be less than zero.

If energy is provided through the NWPP Reserve Sharing Program or its successor, the generator shall purchase the energy at the market index described in the NWPP Reserve Sharing Agreement.

2. Billing Factors

a. The Billing Factor for the rates specified in Sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its Current Transmission Rates website the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. Variable Energy Resource Balancing Service

1. Applicability

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in Section 2.c. of this rate schedule.

Variable Energy Resource Balancing Service (VERBS) is comprised of two components: regulating reserves (which compensate for moment-to-moment differences between generation and load) and non-regulating reserves (which compensate for larger differences occurring over longer periods of time during the hour). VERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

2. Balancing Service

The total charge for VERBS is the applicable rate in Section 2.a. or 2.b., below, plus Formula Balancing Capacity Charges under Section 3, Direct Assignment Charges under Section 4, and Intentional Deviation Penalty Charges under Section 5.

a. VERBS Rates For Wind Resources

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(A)	Regulating Reserves	$0.43 per kilowatt per month
(B)	Non-Regulating Reserves	$0.20 per kilowatt per month

b. VERBS Rates For Solar Resources

Customers taking VERBS will receive BPA's Variable Energy Resource forecast and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(A)	Regulating Reserves	$1.04 per kilowatt per month
(B)	Non-Regulating Reserves	$0.11per kilowatt per month

c. Billing Factor

The Billing Factor for rates in Section 2.a and 2.b is as follows:

(1) For each plant, or phase of a plant, that has completed installation of all units no later than the 15th of the month

prior to the billing month, the billing factor in kilowatts will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(2) For each plant, or phase of a plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kilowatts.

(3) For each plant, or phase of a plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

d. Exceptions

(1) The rates under Section 2.a and 2.b above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the Dynamic Transfer of plant output out of BPA's BAA to another BAA.

(2) Individual rate components under Sections 2.a and 2.b above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of VERBS, including by contractual arrangements for third-party supply.

3. Formula Balancing Capacity Charges

BPA will apply the Balancing Charge to customers to recover the cost of acquiring balancing reserve capacity beyond planned FCRPS capacity.

a. Balancing Charge for Customers

$$Bal.Charge = Cost\ x\ \frac{Indv.Bal.Bill}{Total.Bal.Bills}$$

Where:

Bal.Charge	Balancing Charge – The individual customer's monthly charge for acquiring balancing reserve capacity beyond planned FCRPS capacity.
Cost	Total monthly cost of purchasing or producing balancing reserve capacity beyond planned FCRPS capacity.
Indv.Bal.Bill	Individual Balancing Bill – The sum of an individual customer's monthly charges for services pursuant to ACS.III.E.2.a and ACS.III.E.2.b.
Total.Bal.Bills	Total Balancing Bills – The sum of all monthly charges for services pursuant to ACS.III.E.2.a and ACS.III.E.2.b.

4. Direct Assignment Charges

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide VERBS to the customer if:

a. the customer elected to self-supply in accordance with Section 2.d. but is unable to self-supply one or more components to VERBS; or

b. the customer has a projected generator interconnection date after FY 2028, but chooses to interconnect during the FY 2026-2028 rate period; or

c. the customer elected to dynamically transfer its resource out of BPA's BAA, but the resource remains in the BPA BAA after the date specified in the customer election.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.162 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in Section 2.

5. Intentional Deviation Penalty Charge

Customers taking VERBS under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.L.

F. Dispatchable Energy Resource Balancing Service

The rate below applies to all Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in Section 3 below. Dispatchable Energy Resource Balancing Service (DERBS) is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for DERBS is the charge determined by applying the rates in Section 1 below, plus Direct Assignment Charges in Section 4 below.

1. DERBS Rates

The rates for DERBS will not exceed:

(1)	Incremental Reserves	40.71 mills per kW maximum hourly deviation
(2)	Decremental Reserves	1.38 mills per kW maximum hourly deviation

2. Billing Factors

a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative Station Control Error (under-generation), including ramp periods, that exceeds 3 MW for that hour. When BPA is in the EIM, negative Station Control Error for DERBS billing factors will be based on the measurement value used for determining Uninstructed Imbalance Energy (UIE).

b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive Station Control Error (over-generation), including ramp periods, that exceeds 3 MW for that hour. When BPA is in the EIM, positive Station Control Error for DERBS billing factors will be based on the measurement value used for determining UIE.

3. Exceptions

a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the Dynamic Transfer of plant output out of BPA's BAA to another BAA.

b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's BAA to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

d. Five-minute average station control periods where system frequency deviates by more than 68 megahertz (mHz) will be excluded from determining the maximum positive (decremental) or negative (incremental) value of five-minute station control error for the hour.

4. Direct Assignment Charges

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide DERBS to the customer if:

a. the customer elected to self-supply but is unable to self-supply DERBS; or

b. a customer has a projected generator interconnection date after FY 2028 but chooses to interconnect during the FY 2026-2028 rate period;

c. a customer operating in another BAA chooses to dynamically transfer into the BPA BAA during the FY 2026-2028 rate period; or

d. the customer elected to dynamically transfer its resource out of BPA's BAA but the resource remains in the BPA BAA after the date specified in the customer election.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.162 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in Section 1.

5. Persistent Deviation

Transmission Customers taking DERBS will be subject to the Persistent Deviation Penalty Charge pursuant to GRSP II.M.1.

G. New Generation Technology Pilot Program

A customer and BPA may jointly develop a pilot program at the individual generation project level to integrate new technology such as fuel cells or to integrate new uses of technology such as a solar project coupled with a co-located battery. The goal of the pilot is to determine the balancing reserve capacity a new technology needs, or, for a generator co-located with a battery, to reduce the combined project's balancing reserve capacity burden placed on the BPA BAA. In place of any normally applicable RFR, VERBS or DERBS rates, BPA will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following reserve capacity rate components:

1.	Regulating INC Reserves	$0.317 per kilowatt-day
2.	Non-Regulating INC Reserves	$0.162 per kilowatt-day
3.	Regulating DEC Reserves	$0.007 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project). For the co-located generator and battery, the total rate shall not exceed the total cost of the normally applicable RFR, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project will apply. A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties.

SECTION IV. ENERGY IMBALANCE MARKET SERVICES AND RATES

The rates below will apply when Energy Imbalance (EI) and Generation Imbalance (GI) services are provided pursuant to Tariff Schedules 4E and 9E of the BPA Tariff.

Capitalized terms not otherwise defined by this section will have the meaning set forth in the BPA Tariff.

A. Imbalance Charges – Tariff Schedules 4E And 9E

1. Energy Imbalance Service (Schedule 4E) (EIM)

a. EI Service

A Transmission Customer shall be charged or paid for EI Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule (as determined pursuant to Section 4.2.4 of Attachment Q of the BPA Tariff) settled as UIE for the period of the deviation at the applicable hourly Load Aggregation Point (LAP) price where the load is located as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

Transmission Customers taking EI Service will be subject to the Persistent Deviation Penalty Charge for UIE pursuant to GRSP II.M.2.

b. Temporary Contingency Rate

In the event of a temporary contingency requiring corrective action under Section 10.3.1(1) of Attachment Q to the BPA Tariff, where the MO requests an alternative price under Section 29.7(j)(2)(D) of the MO Tariff, BPA shall request the MO settle the deviation using an available energy index in the Pacific Northwest.

2. Generation Imbalance Service (Schedule 9E) (EIM)

a. GI Service When No Schedule Changes Occur to Resource After T-57.

Except as provided for in Section 2.b. below, Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Transmission Customer's metered generation compared to the resource component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable PNode

RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

b. GI Service When Changes Occur To Resource Schedule After T-57

For Transmission Customers that have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or if the scheduled output of a resource changes after T-57, the following provisions will apply:

(1) GI – Uninstructed Imbalance Energy Charges/Credits

(A) UIE/RTD (Metered Gen - Scheduled Output at RTD)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

Transmission Customers taking GI Service will be subject to the Persistent Deviation Penalty Charge for UIE pursuant to GRSP II.M.1.

(2) GI – Instructed Imbalance Energy Charges/Credits

(A) FMM-IIE (Scheduled Output at FMM - TCBS)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in the FMM (FMM Schedule), compared to the resource component of the Transmission Customer Base Schedule, settled as IIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO in Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

(B) RTD-IIE (Scheduled Output at RTD –FMM)

A Transmission Customer shall be charged or paid for GI Service measured as the deviation of the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or the scheduled output of a resource incorporated by the MO in RTD, compared to the FMM Schedule, as IIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

(C) Intrachange Imbalance Adjustment.

If a Transmission Customer elects to receive Intrachange Imbalance pursuant to the BPA EIM Business Practice, then the FMM-IIE and RTD-IIE associated with such Intrachange will be settled with the resource in accordance with Section IV.B.2 of this section.

c. Non-EIM Balancing Rate

In addition to the charges or payments under ACS IV.A.2, a Transmission Customer shall be charged or paid for GI Service, if any component of the Transmission Customer Base Schedule used by the MO for settlement differs from the components of the Transmission Customer Base Schedule submitted to the BPA EIM entity. The rate for Non-EIM Balancing shall be the same PNode RTD price used to calculate charges under ACS IV.A.2 for the same time period.

d. Temporary Contingency Rate

In the event of a temporary contingency requiring corrective action under Section 10.3.1(1) of Attachment Q to the BPA Tariff, where the MO requests an alternative price under Section 29.7(j)(2)(D) of the MO Tariff, BPA shall request the MO settle the deviation using an available energy index in the Pacific Northwest.

B. Interchange And Intrachange Imbalance

1. Interchange Imbalance

Interchange Imbalance is assessed when deviations occur between the Interchange portion of a Transmission Customer's Base Schedule and the schedule value at the applicable Fifteen-Minute Market (FMM) or Real-Time Dispatch (RTD) market interval. Transmission Customers with Interchange Imbalance will be assessed IIE at either the FMM Locational Marginal Price (LMP), the RTD LMP, or both, depending upon when the changes to the Transmission Customer's Interchange are incorporated by the MO into the applicable EIM market run. Interchange Imbalance will be calculated as follows:

a. Calculation of Interchange Imbalance – FMM-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the Interchange portion of the Transmission Customer's Base Schedule compared to the Interchange schedule incorporated by the MO in the FMM (FMM Schedule). Such imbalance will be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the Interchange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

b. Calculation of Interchange Imbalance – RTD-IIE

A Transmission Customer shall be charged or paid for Interchange Imbalance measured as the deviation of the FMM Schedule compared to the Interchange schedule incorporated by the MO in the RTD. Such imbalance will be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the Interchange is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

2. Intrachange Imbalance

Intrachange Imbalance is assessed when deviations occur between the Intrachange portion of a Transmission Customer's Base Schedule and the Transmission Customer's Intrachange schedule at an applicable FMM or RTD market interval. BPA will assess Intrachange Imbalance when requested by Power Services or a Transmission Customer and upon meeting the requirements in the BPA EIM Business Practice. Intrachange Imbalance will be assessed IIE at either the FMM LMP, the RTD LMP, or both, depending upon when the changes to the Transmission Customer's Intrachange occurs.

Intrachange Imbalance will be calculated as follows:

a. Calculation of Intrachange Imbalance – FMM-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the Intrachange portion of the Transmission Customer's Base Schedule compared to the Transmission Customer's Intrachange schedule at the applicable FMM interval (FMM Schedule). Such imbalance will be settled as FMM-IIE for the period of the deviation at the applicable PNode FMM price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff.

b. Calculation of Intrachange Imbalance – RTD-IIE

A Transmission Customer shall be charged or paid for Intrachange Imbalance measured as the deviation of the FMM Schedule compared to the Transmission Customer's Intrachange schedule at the applicable RTD interval. Such imbalance will be settled as RTD-IIE for the period of the deviation at the applicable PNode RTD price where the source resource responsible for the Intrachange is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

c. Adjustment to IIE Settlement for Source Resource Responsible for an Intrachange

The source resource responsible for an Intrachange will be charged or paid an amount of Intrachange Imbalance that exactly offsets the Intrachange Imbalance paid or charged the Transmission Customer under Sections IV.B.2.a and b above.

d. Applicability to Interchange

Power Services or a Transmission Customer may elect to have an Interchange Imbalance settlement adjusted in the same manner as an Intrachange Imbalance by making such election pursuant to the BPA EIM Business Practice.

C. Charges For Under-Scheduling or Over-Scheduling Load

1. Under-Scheduling Load

Any charges to the BPA EIM entity pursuant to Section 29.11(d)(1) of the MO Tariff for under scheduling load will be assigned to the Transmission Customers subject to Schedule 4 based on each Transmission Customer's respective under-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's under-scheduled load imbalance amount relative to all other Transmission Customers' under-scheduled load imbalance amounts who have under-scheduled load for the Operating Hour, expressed as a percentage.

2. Over-Scheduling Load

Any charges to the BPA EIM entity pursuant to Section 29.11(d)(2) of the MO Tariff for overscheduling load will be assigned to the Transmission Customers subject to Schedule 4 based on each Transmission Customer's respective over-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's over-scheduled load imbalance amount relative to all other Transmission Customers' over-scheduled load imbalance amounts who have over-scheduled load for the Operating Hour, expressed as a percentage.

3. Distribution Of Under-Scheduling Or Over-Scheduling Proceeds

Any payment to the BPA EIM Entity pursuant to Section 29.11(d)(3) of the MO Tariff will be distributed to Transmission Customers on the basis of EIM Metered Demand whose daily average absolute Schedule 4E UIE is less than 5 percent or 2 MW (whichever is greater) of its daily average schedule. For those Transmission Customers that qualify to receive proceeds, the proceeds will be allocated based on a ratio of each Transmission Customer's daily average EIM Metered Demand relative to aggregate daily average EIM Metered Demand of all other Transmission Customers' who are eligible to receive proceeds for that day.

D. EIM Neutrality And Uplift Charges And Credits

1. EIM BAA Real-Time Market Neutrality (Real-Time Imbalance Energy Offset EIM)

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(3) of the MO Tariff for EIM BAA real-time market neutrality will be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

2. EIM Entity BAA Real-Time Congestion Offset

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(2) of the MO Tariff for the EIM real-time congestion offset will be allocated to Transmission Customers on the basis of EIM Measured Demand.

3. EIM Entity Real-time Marginal Cost of Losses Offset

Any charges to the BPA EIM entity pursuant to Section 29.11(e)(4) of the MO Tariff for real-time marginal cost of losses offset will be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

4. EIM Neutrality Settlement (Real-Time System Imbalance Energy Offset)

Any charges to the BPA EIM Entity pursuant to Section 29.11(e)(5) of the MO Tariff for EIM neutrality settlement will be sub-allocated as follows:

Description	Allocation
Neutrality Adjustment (monthly and daily)	EIM Measured Demand
Rounding Adjustment (monthly and daily)	EIM Measured Demand

5. Real-Time Unaccounted For EIM Energy Settlement (UFE)

Any charges to the BPA EIM entity pursuant to Section 29.11(c) of the MO Tariff for UFE will be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

E. Flexible Ramping Product

Any charges to the BPA EIM Entity pursuant to Section 29.11(p) of the MO Tariff for the Flexible Ramping Product will be allocated to Transmission Customers based on EIM Measured Demand.

F. Real-Time Bid Cost Recovery

Any charges or payments to the BPA EIM Entity pursuant to Section 29.11(f) of the MO Tariff for EIM real-time bid cost recovery will be allocated to Transmission Customers based on EIM Measured Demand.

G. Rolled In Charges

All other charges or credits assessed by the MO to the BPA EIM entity that are not otherwise allocated by this Section IV will be rolled in and recovered through base Transmission rates.

H. Other Charges and Provisions

1. MO Tax Liabilities

Any charges to the BPA EIM entity pursuant to Section 29.22(a) of the MO Tariff for MO tax liability as a result of the EIM will be sub-allocated to those Transmission Customers triggering the tax liability.

2. Market Validation and Price Correction

If the MO modifies the BPA EIM entity settlement statement in accordance with the MO's market validation and price correction procedures in the MO Tariff, the BPA EIM entity reserves the right to make corresponding or similar changes to the charges and payments suballocated under this Section IV.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. Rate Adjustment Due to FERC Order Under FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.C.

B. Rate Adjustment for Transmission Cost Recovery Adjustment Clause, Transmission Reserves Distribution Clause, and Transmission Financial Reserves Policy Surcharge

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause (CRAC), the Transmission Reserves Distribution Clause (RDC), and the Transmission Financial Reserves Policy (FRP) Surcharge, specified in GRSPs II.G, II.H, and II.I.

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GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

A. Approval Of Rates

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

B. General Provisions

These BP-26 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-24 rate schedules, which became effective October 1, 2023, to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs will be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C.§ 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C.§ 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C.§ 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C.§ 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C.§ 824(i)–(l).

These BP-26 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. 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.

D. Billing and Payment

1. Billing Procedure

Within a reasonable time after the first day of each month, BPA shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff and other agreements during the preceding month. The invoice will be paid by the Transmission Customer within

twenty (20) days of receipt. All payments will be made in immediately available funds payable to BPA, or by wire transfer to a bank named by BPA.

2. Interest On Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) will be calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts will be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills will be considered as having been paid on the date of receipt by BPA.

3. Billing Disputes

Any billing dispute must be initiated in accordance with and follow the dispute resolution procedures in Section 12 of the Tariff and any business practices implementing that section.

4. Customer Default

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BPA on or before the due date as described above, and such failure of payment is not corrected within 30 calendar days after BPA notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BPA may notify the Transmission Customer that it plans to terminate services in sixty (60) days. The Transmission Customer may use the dispute resolution procedures to contest such termination.

In the event of a billing dispute between BPA and the Transmission Customer, BPA will continue to provide service under the Service Agreement as long as the Transmission Customer i) continues to make all payments not in dispute, and ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BPA may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with FERC policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Delivery Charge

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery facilities and equipment. The DSI Delivery Charge will be as specified in Section III of the Use-of-Facilities (UFT-26) Rate schedule.

B. Failure To Comply Penalty Charge

If a party fails to comply with BPA's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. Parties that are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a *force majeure* on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify BPA of the situation upon occurrence of the *force majeure*.

1. Rates

The rate will be the greater of 500 mills per kWh or:

a. For generators, 150 percent of the applicable RTD LMP, based on the PNode RTD where the generator is located, as determined by the Market Operator (MO) under Section 29.11(b)(3)(B) of the MO Tariff.

b. For load, 150 percent of the applicable hourly Load Aggregation Point (LAP) price for BPA as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, the rate will be the greater of 500 mills per kWh or 150 percent of an available energy index in the Pacific Northwest.

2. Billing Factor

The Billing Factor for the Failure to Comply Penalty Charge will be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten (10) minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the OATT or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation

levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by BPA in accordance with the curtailment or redispatch provisions of the OATT or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. Waiver or Reduction of a Failure To Comply Penalty Charge

BPA may, in its sole discretion, waive or reduce a Failure to Comply Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction in a Failure to Comply Penalty Charge, a customer must submit a request demonstrating that the events resulting in a Failure to Comply Penalty Charge were:

a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and

b. Immediately corrected upon discovery of the technical error or malfunction.

BPA may also consider the customer's frequency of incurring Failure to Comply Penalty Charges in deciding whether to waive or reduce a Failure to Comply Penalty Charge.

C. Rate Adjustment Due to FERC Order Under FPA § 212

If, after review by FERC, the NT, PTP, ACS, IS, or IM rate schedule, as initially submitted to FERC, is modified to satisfy the standards of Section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications will automatically apply to the rate schedule for non-Section 212(i)(1)(B)(ii) transmission service. The modifications for non-Section 212(i)(1)(B)(ii) transmission service, as described above, will be effective only prospectively from the date of the final FERC order granting final approval of the rate schedule for FERC-ordered transmission service pursuant to Section 212(i)(1)(B)(ii). No refunds will be made or additional costs charged as a consequence of this prospective modification for any non-Section 212(i)(1)(B)(ii) transmission service that occurred under the rate schedule prior to the effective date of such prospective modification.

D. Reservation Fee

The Reservation Fee is a non-refundable fee that will be charged to any PTP Transmission Service customer that postpones the Commencement of Service by requesting an extension of the Service Commencement Date specified in the executed Service Agreement.

For each extension of the Service Commencement Date, the Reservation Fee is equal to one month's charge for the requested Long-Term Firm PTP Transmission Service. The Reservation Fee will be specified in the executed Service Agreement.

E. Transmission and Ancillary Services Rate Discounts

BPA may offer discounted rates for transmission service and for ancillary services provided in conjunction with the provision of transmission service. Three principal requirements apply to discounts for transmission and ancillary services, as follows:

1. Any offer of a discount made by BPA must be announced to all Eligible Customers solely by posting on the OASIS;

2. Any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and

3. Once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for transmission service on a path, from point(s) of receipt to point(s) of delivery, BPA must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that connect to the same point(s) of delivery on the same segment of the transmission system.

A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BPA's transmission system.

F. Unauthorized Increase Charge (UIC)

Transmission Customers taking PTP Transmission Service under the PTP, IS, and IM rate schedules will be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). BPA will notify a Transmission Customer that is subject to a UIC once BPA has verified the UIC amount.

1. Rates

The UIC rate will be the lesser of a) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or b) 500 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

2. Billing Factors

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way Dynamic Schedules, BPA shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA will sum these amounts that exceed capacity reservations for all PODs and for all PORs. The Billing Factor for the monthly billing period will be the greater of the total of the POD hourly amounts or the total of the POR hourly amounts.

3. UIC Relief

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A Transmission Customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UIC:

(1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen or avoided; and

(2) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

BPA may also consider a Transmission Customer's frequency of incurring UICs in deciding whether to waive or reduce a UIC.

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA OASIS website.

b. Transmission Rate if BPA Waives or Reduces the UIC

If BPA waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates will apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS, or IM rate schedules if BPA waives or reduces the UIC:

(1) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for one day of service under Section II.B.1 of the applicable PTP, IS, or IM rate schedule will apply.

(2) If BPA waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under Section II.B.1 of the applicable PTP, IS, or IM rate schedule will apply.

(3) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under Section II.B.1 of the applicable PTP, IS, or IM rate schedule will apply.

For a Transmission Customer taking PTP Transmission Service under the PTP, IS, or IM rate schedules, the Billing Factor for rates in this Section 3.b. will be: a) the Transmission Customer's highest excess transmission demand for which BPA waives the UIC; or b) if BPA reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

G. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

The Transmission CRAC is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-26)
- Point-to-Point Rate (PTP-26)
- Southern Intertie Point-to-Point Rate (IS-26)
- Scheduling, System Control, and Dispatch Rate (ACS-26)
- Montana Intertie Rate (IM-26)

1. Transmission 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 Transmission Services (Transmission RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Transmission 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 Transmission CRAC Amount

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

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

(1) If the underrun minus the Revenue Financing Amount is less than $5 million, there is no Transmission 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 Transmission CRAC 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 $100 million, the Transmission CRAC Amount is equal to $100 million.

The Transmission CRAC Cap and Thresholds are shown in Table A.

Table A
Transmission CRAC Annual Thresholds and Caps
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2025	2026	$0	$125	$100
2026	2027	$0	$125	$100
2027	2028	$0	$125	$100

b. Converting the Transmission CRAC Amount to the Transmission CRAC Percentage and Calculating Revised Rates

The Transmission CRAC Percentage is calculated by dividing the Transmission CRAC Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10-month period of December through September of the applicable year.

The Transmission CRAC Percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission CRAC 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 transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission CRAC Amount.

b. Notification of Transmission CRAC Trigger

By November 30, 2025, BPA will complete the calculation of Transmission RFR as of the end of FY 2025, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2026.

By November 30, 2026, BPA will complete the calculation of Transmission RFR as of the end of FY 2026, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2027.

By November 30, 2027, BPA will complete the calculation of Transmission RFR as of the end of FY 2027, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2028.

If the Transmission CRAC triggers, BPA will notify customers of the preliminary Transmission CRAC Amount to be recovered by the Transmission CRAC Percentage 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 Transmission CRAC Percentage.

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

H. Transmission Reserves Distribution Clause (Transmission RDC)

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

If the Transmission RDC quantitative criteria (below) are met, the Administrator will calculate the Transmission RDC Amount and apply such amount to rate reduction through a Transmission Dividend Distribution (Transmission DD).

A Transmission DD is a downward adjustment that applies to these Transmission rates:

- Network Integration Rate (NT-26)
- Point-to-Point Rate (PTP-26)
- Southern Intertie Point-to-Point Rate (IS-26)
- Scheduling, System Control, and Dispatch Rate (ACS-26)
- Montana Intertie Rate (IM-26)

1. Transmission 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 Transmission Services (Transmission RFR) and financial reserves available for risk that are attributed to BPA (BPA RFR) as of the fiscal year preceding the applicable year. If Transmission RFR is greater than the Transmission 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 the Transmission RDC Amount and apply such amount to rate reduction through a Transmission DD. The resulting rate decrease will go into effect beginning the month following the issuance of the final Transmission RDC Amount through September 30 of the applicable year.

a. Calculating the Transmission RDC Amount

The Transmission RDC can trigger only if i) Transmission RFR exceeds the Transmission RDC Threshold and ii) BPA RFR exceeds the BPA RDC Threshold.

The Transmission RDC Amount will be the smallest of:
Transmission RFR minus the Transmission RDC Threshold; or
BPA RFR minus the BPA RDC Threshold.

Table B
Transmission RDC Annual Thresholds
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Transmission RFR Threshold
2025	2026	$283
2026	2027	$283
2027	2028	$283

Table C
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	$768
2026	2027	$768
2027	2028	$768

b. Converting a Transmission DD to the Transmission DD Percentage and Calculating Revised Rates

The Transmission DD Credit Percentage is calculated by dividing the Transmission DD Amount by the sum of the most recent forecasts of revenues from the applicable rates for the period beginning the month following the issuance of the final Transmission RDC amount through September of the applicable year.

The Transmission DD Credit Percentage is subtracted from 1.0 and then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission 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 transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission RDC Amount.

b. Notification of Transmission RDC Trigger

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

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

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

If the Transmission RDC triggers, BPA will notify customers of the preliminary Transmission RDC Amount. Such notice will 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 Transmission RDC Amount.

BPA will hold at least one public meeting to discuss the calculations of Transmission RFR, the Transmission RDC Amount, the Transmission DD Credit Amount, and the Transmission DD Credit percentage. BPA will issue the final Transmission RDC Amount by December 15 of each applicable year, unless extended by BPA. If BPA extends the timeframe for issuing the final Transmission RDC Amount, BPA will identify the new date for issuing such decision in a public notice. Such date will be no later than February 1 of the following year.

I. Transmission Financial Reserves Policy Surcharge (Transmission FRP Surcharge)

The Transmission FRP Surcharge is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-26)
- Point-to-Point Rate (PTP-26)
- Southern Intertie Point-to-Point Rate (IS-26)
- Scheduling, System Control, and Dispatch Rate (ACS-26)
- Montana Intertie Rate (IM-26)

1. Transmission 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 Transmission Services (Transmission RFR) as of the end of the fiscal year preceding the applicable year. Based on the calculations below, a Transmission 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 Transmission FRP Surcharge Amount

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

The Transmission 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 Transmission 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 Transmission 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 FRP Surcharge Amount is equal to the Base Surcharge.

The Transmission FRP Surcharge Thresholds and Base Surcharge are shown in Table D.

Table D
Transmission FRP Surcharge Annual Thresholds and Caps
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Base Surcharge
2025	2026	$141	$125	$15
2026	2027	$141	$125	$15
2027	2028	$141	$125	$15

b. Converting the Transmission FRP Surcharge Amount to the Transmission FRP Surcharge Percentage and Calculating Revised Rates

The Transmission FRP Surcharge Percentage is calculated by dividing the Transmission FRP Surcharge Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10-month period of December through September of the applicable year.

The Transmission FRP Surcharge Percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. Transmission 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 transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission FRP Surcharge Amount.

b. Notification of Transmission FRP Surcharge

By November 30, 2025, BPA shall complete the calculation of Transmission RFR as of the end of FY 2025, for use in calculating the

Transmission FRP Surcharge applicable to rates for December through September of FY 2026.

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

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

If the Transmission FRP Surcharge triggers, BPA will notify customers of the preliminary Transmission FRP Surcharge Amount to be recovered by the Transmission 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 Transmission RFR, the Transmission FRP Surcharge Amount, and the Transmission FRP Surcharge percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission FRP Surcharge Amount and the Transmission FRP Surcharge percentage as soon as practicable, but in no case later than December 15 of each applicable year.

J. Real Power Loss Imbalance Settlement

The Real Power Loss Imbalance Settlement rate applies to the settlement of imbalance associated with return of Real Power Losses by a Transmission Customer that elects In-Kind Loss Return Service or Slice Output Loss Return Service.

1. Rate

The rate will be the greater of $0 or the applicable 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. 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.

2. Billing Factors

The Billing Factor (in kilowatthours) will be the Transmission Customer's total loss imbalance for the hour, which consists of:

a. Kilowatthour remainders that result from rounding the calculation of the quantity of Real Power Losses the Transmission Customer is obligated to physically return via e-Tag; and

b. Time-based imbalances that result from changes that occur after the calculation of the quantity of Real Power Losses the Transmission Customer is obligated to physically return via e-Tag.

K. Invalid Loss Return Penalty (ILRP) Charge

The Invalid Loss Return Penalty Charge (ILRP Charge) applies to a Transmission Customer that elects In-Kind Loss Return Service when the customer returns a different quantity of Real Power Losses via e-Tag than the customer is obligated to return.

1. Rates

a. Energy Price

The energy price will be the applicable 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. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

b. Under-Delivery Event (UDE)

For each hour the Transmission Customer returns less energy than the quantity of Real Power Losses the customer is obligated to physically return via e-Tags, the ILRP rates will be:

(1) UDE Capacity Rate: 5.58 mills per kilowatthour.

(2) UDE Energy Rate: the greater of $0 or 250 percent of the Energy Price.

c. Over-Delivery Event (ODE)

For each hour the Transmission Customer returns more energy than the quantity of Real Power Losses the customer is obligated to physically return via e-Tags, the ILRP rates will be:

(1) ODE Capacity Rate: 5.58 mills per kilowatthour.

(2) ODE Energy Rate: 250 percent of the absolute value of the Energy Price.

The ODE Energy Rate will not be assessed in an hour when the Energy Price is equal to or greater than $0 per megawatthour.

2. Billing Factors

a. Under-Delivery Event

The Billing Factor (in kilowatthours) for the UDE rates will be for each hour:

The quantity of Real Power Losses the Transmission Customer must physically return via e-Tags

Minus

The quantity of Real Power Losses the Transmission Customer physically returns via e-Tags.

b. Over-Delivery Event

The Billing Factor (in kilowatthours) for the ODE rates will be for each hour:

The quantity of Real Power Losses the Transmission Customer physically returns via e-Tags

Minus

The quantity of Real Power Losses the Transmission Customer must physically return via e-Tags.

3. Other Provisions

BPA will exempt a Transmission Customer from the ILRP charge:

a. For any hour in which BPA has waived the customer's obligation to return Real Power Losses under the Oversupply Management Protocol.

b. For any hour in which a Transmission Provider has issued a curtailment or reload that impacts the customer's BPA-calculated loss obligation or the customer's loss return e-tag between T-67 prior to the start of the hour of flow and the end of the hour of flow.

(1) If a single curtailment or reload spans more than one consecutive hour, only the first hour of flow is exempt from the ILRP charge.

4. Waiver or Reduction of Charge

BPA may, in its sole discretion, waive or reduce an ILRP Charge if requested by the Transmission Customer for good cause shown. In order to qualify for a waiver or reduction of an ILRP Charge, the Transmission Customer must submit a request demonstrating that the events resulting in the charge were due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care.

BPA may also consider the Transmission Customer's frequency of incurring ILRP Charges in deciding whether to waive or reduce a charge.

L. Intentional Deviation Penalty Charge

1. Applicability

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-26 VERBS rate.

Exceptions:

a. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

2. Rate

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1

(See Section 3, below, for definition of terms.)

3. Billing Factor

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

a. for wind generating customers taking VERBS under rate schedule Section 2.a., the applicable schedule value provided by BPA;

b. for solar generating customers taking VERBS under rate schedule Section 2.b., the applicable schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer integrated over the hour.

4. Other Provisions

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS (Station Control Error) ≤ ABS (Intentional Deviation Measurement Value Error) + 1 MW

Where:

ABS (Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value. Any interval in which a Variable Energy Resource that is a Participating Resource in the EIM receives an instructed dispatch from the Market Operator is excluded from the calculation of Station Control Error and Intentional Deviation Measurement Value Error.

5. Waiver or Reduction of Intentional Deviation Penalty Charge

BPA may, in its sole discretion, waive or reduce an Intentional Deviation Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction of an Intentional Deviation Penalty Charge, a customer must submit a request demonstrating that the events resulting in an Intentional Deviation Penalty Charge were:

a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and

b. Immediately corrected upon discovery of the technical error or malfunction.

BPA may also consider the customer's frequency of incurring Intentional Deviation Penalty Charges in deciding whether to waive or reduce an Intentional Deviation Penalty Charge.

M. Persistent Deviation Penalty Charge

1. Dispatchable Energy Resource Balancing Service

a. Applicability

For Dispatchable Energy Resources taking DERBS pursuant to ACS III.F, the Persistent Deviation Penalty Charge applies to all hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

(1) both 15 percent of the integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(2) both 7.5 percent of the integrated hourly schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the integrated hourly schedule and 5 MW in each scheduled period for 12 consecutive hours or more in the same direction; or

(4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

When BPA is in the EIM, positive or negative deviations will be based on the measurement value used for determining UIE.

b. Rate

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of i) 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS III.B, or the highest RTD LMP at the closest point of interconnection during the period of penalty for service under ACS IV.A.2, or ii) 100 mills per kilowatthour; less any charges assessed pursuant to ACS III.B or IV.A.2. For Participating Resources in the EIM the charge is the greater of i) 25 percent of the highest RTD LMP at the closest point of interconnection during the period of penalty, or ii) 100 mills per

kilowatthour minus the highest RTD LMP at the closest point of interconnection during the period of penalty.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the penalty will not be applied for any periods of negative index.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

2. Energy Imbalance Service

a. Applicability

For customers taking EI Service pursuant to ACS II.D and IV.A.1, the Persistent Deviation Penalty Charge applies to all hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(1) both 15 percent of the integrated hourly schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

(2) both 7.5 percent of the integrated hourly schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the integrated hourly schedule and 5 MW in each scheduled period for 12 consecutive hours or more in the same direction; or

(4) both 1.5 percent of the integrated hourly schedule and 2 MW in each scheduled period for 24 consecutive hours or more in the same direction.

For EI Service pursuant to ACS IV.B.1, positive or negative deviations will be based on the measurement value used for determining UIE pursuant to that section.

b. Rate

No credit is given when energy taken is less than the scheduled energy.

When energy taken exceeds the scheduled energy, the charge is the greater of a) 125 percent of either BPA's highest incremental cost that occurs during that day for service under ACS II.D, or the highest LAP during the period of penalty for service under ACS IV.A.1, or
b) 100 mills per kilowatthour; less any charges assessed pursuant to ACS II.D or IV.A.1.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the penalty will not be applied for any periods of negative index.

3. Pattern Of Conduct

A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day. For GI Service, the rate under Section 1.b above shall apply, and for EI Service, the rate under Section 2.b above shall apply.

4. Reduction or Waiver of Persistent Deviation Penalty

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

N. Generator Interconnection Withdrawal Charge

For Interconnection Customers with an Interconnection Request studied in a Cluster Study under Attachment L, Standard Large Generator Interconnection Procedures (LGIP), of BPA's Open Access Transmission Tariff (OATT), the Generator Interconnection Withdrawal Charge (GIW Charge) applies after executing a Phase Two Cluster Study Agreement and subsequently a) the Interconnection Request for which the agreement was executed is withdrawn or deemed withdrawn as specified in Section 3.7 of the LGIP, or b) the Generating Facility associated with the Interconnection Request fails to reach Commercial Operation.

Transition Process. For Interconnection Customers with an Interconnection Request studied in the Transition Cluster Study under Attachment R of BPA's OATT, the GIW Charge applies after executing an Interconnection Facilities Study Agreement and subsequently a) the Interconnection Request for which the agreement was executed is withdrawn or deemed withdrawn as specified in Section 3.7 of the LGIP, or b) the Generating Facility associated with the Interconnection Request fails to reach Commercial Operation.

Capitalized terms in this rate schedule that are not defined in Section III of the GRSPs have the meaning in BPA's OATT.

1. Charges

a. If an Interconnection Request is withdrawn or deemed withdrawn after the Interconnection Customer executes a Phase Two Cluster Study Agreement but prior to the execution of an Interconnection Facilities Study Agreement for the Interconnection Request, the charge will be two times the Phase Two Cluster Study Deposit for the Interconnection Request as specified in Section 7.1.1 of the LGIP.

b. If an Interconnection Request is withdrawn or deemed withdrawn after the Interconnection Customer executes an Interconnection Facilities Study Agreement but prior to the execution of a Standard Large Generator Interconnection Agreement (LGIA) for the Interconnection Request, the charge will be 10 percent of the Interconnection Request's share of estimated Network Upgrade costs as identified in the study report most recently issued prior to withdrawal.

c. If an Interconnection Request is withdrawn or deemed withdrawn or an Interconnection Request's Generating Facility otherwise does not reach Commercial Operation after the execution and funding of a LGIA, the charge will be 20 percent of the Interconnection

Request's share of estimated Network Upgrade costs as identified in the LGIA.

d. For Interconnection Customers with an Interconnection Request studied in the Transition Cluster Study under Attachment R of BPA's OATT, the GIW Charge may not exceed $5 million.

e. For Interconnection Customers with an Interconnection Request studied in a Cluster Study under the LGIP, the GIW Charge may not exceed $10 million.

2. Other Provisions

An Interconnection Customer will not be assessed a GIW Charge for withdrawal of an Interconnection Request if:

a. The withdrawal of the Interconnection Request does not have a material impact on the cost or timing of any other Interconnection Request in the same Cluster.

b. The estimated Network Upgrade costs assigned to the Interconnection Request in the most recent Cluster Study Report issued to the Interconnection Customer prior to withdrawal increased by more than 40 percent from the estimated Network Upgrade costs assigned to the Interconnection Request in the preceding Cluster Study Report issued to the Interconnection Customer.

c. The estimated Network Upgrade costs assigned to the Interconnection Request in the most recent Facilities Study report issued to the Interconnection Customer prior to withdrawal increased by more than 100 percent from the estimated Network Upgrade costs assigned to the Interconnection Request in the final Phase Two Cluster Study report issued to the Interconnection Customer.

d. The estimated Network Upgrade costs assigned to the Interconnection Request identified in the LGIA increased by more than 100 percent from the estimated Network Upgrade costs assigned to the Interconnection Request in the final Phase Two Cluster Study report issued to the Interconnection Customer.

e. The estimated Network Upgrade costs under Section 2.c and 2.d above will include the Interconnection Request's share of the costs of any Network Upgrades identified in an Affected System study report provided to BPA prior to withdrawal.

f. BPA does not issue a final Phase Two Cluster Study report for more than four years after initiating the Cluster Study that included the Interconnection Request that has been withdrawn or deemed withdrawn and the Interconnection Customer withdraws the Interconnection Request within 30 business days after four years from the initiation of the Cluster Study.

g. BPA does not issue an Interconnection Facilities Study report within two times the estimated completion time as identified in the Interconnection Facilities Study Agreement.

3. Waiver or Reduction of Charge

BPA may, in its sole discretion, waive or reduce a GIW Charge if requested by the Interconnection Customer for good cause shown. In order to qualify for a waiver or reduction of a GIW Charge, the Interconnection Customer must submit a request demonstrating that the events resulting in the charge could not have been avoided through the exercise of reasonable care. BPA may also consider the frequency that Interconnection Customer is incurring GIW Charges in deciding whether to waive or reduce a charge.

O. Modified Tier 1 Cost Allocators (TOCA) for Oversupply Rate

BPA Customer ID	Customer Name	Modified TOCAs		
		FY2026	FY2027	FY2028
10015	Asotin County PUD #1	0.0000854	0.0000848	0.0000844
10024	Benton County PUD #1	0.0299002	0.0296892	0.0295602
10025	Benton REA	0.0088782	0.0088155	0.0087772
10027	Big Bend Elec Coop	0.0091065	0.0090423	0.0090030
10029	Blachly Lane Elec Coop	0.0026215	0.0026030	0.0025917
10044	Canby, City of	0.0030222	0.0030009	0.0029879
10046	Central Electric Coop	0.0121806	0.0120946	0.0120421
10047	Central Lincoln PUD	0.0224191	0.0222832	0.0222309
10055	Albion, City of	0.0000592	0.0000588	0.0000586
10057	Ashland, City of	0.0028435	0.0028234	0.0028119
10059	Bandon, City of	0.0011368	0.0011288	0.0011239
10061	Blaine, City of	0.0013016	0.0012924	0.0012868
10062	Bonners Ferry, City of	0.0007916	0.0007860	0.0007826
10064	Burley, City of	0.0020929	0.0020782	0.0020691
10065	Cascade Locks, City of	0.0003538	0.0003513	0.0003497
10066	Centralia, City of	0.0036269	0.0036013	0.0035856
10067	Cheney, City of	0.0023538	0.0023372	0.0023271
10068	Chewelah, City of	0.0003729	0.0003703	0.0003685
10070	Declo, City of	0.0000534	0.0000531	0.0000528
10071	Drain, City of	0.0002810	0.0002793	0.0002781
10072	Ellensburg, City of	0.0035688	0.0035436	0.0035282
10074	Forest Grove, City of	0.0039706	0.0039426	0.0039255
10076	Heyburn, City of	0.0007169	0.0007118	0.0007087
10078	McCleary, City of	0.0005504	0.0005480	0.0005469
10079	McMinnville, City of	0.0124801	0.0124241	0.0123688
10080	Milton, Town of	0.0009862	0.0009796	0.0009757
10081	Milton-Freewater, City of	0.0013826	0.0013728	0.0013666
10082	Minidoka, City of	0.0000171	0.0000170	0.0000168
10083	Monmouth, City of	0.0012445	0.0012358	0.0012304
10086	Plummer, City of	0.0003774	0.0003759	0.0003752
10087	Port Angeles, City of	0.0072321	0.0071810	0.0071500
10089	Richland, City of	0.0155084	0.0153990	0.0153321
10091	Rupert, City of	0.0013994	0.0013895	0.0013832
10094	Soda Springs, City of	0.0004125	0.0004109	0.0004102
10095	Sumas, Town of	0.0005422	0.0005383	0.0005360

BPA Customer ID	Customer Name	Modified TOCAs		
		FY2026	FY2027	FY2028
10097	Troy, City of	0.0002963	0.0002949	0.0002940
10101	Clallam County PUD #1	0.0113140	0.0112342	0.0111854
10103	Clark County PUD #1	0.0473964	0.0470618	0.0468575
10105	Clatskanie PUD	0.0128094	0.0127248	0.0127110
10106	Clearwater Power	0.0035535	0.0035284	0.0035130
10109	Columbia Basin Elec Coop	0.0018033	0.0017906	0.0017828
10111	Columbia Power Coop	0.0004760	0.0004724	0.0004706
10112	Columbia River PUD	0.0086685	0.0086073	0.0085699
10113	Columbia REA	0.0056093	0.0055697	0.0055455
10116	Consolidated Irrigation District #19	0.0000339	0.0000336	0.0000335
10118	Consumers Power	0.0067969	0.0067489	0.0067196
10121	Coos Curry Elec Coop	0.0059464	0.0059044	0.0058784
10123	Cowlitz County PUD #1	0.0682492	0.0677528	0.0673395
10136	Douglas Electric Cooperative	0.0027343	0.0027218	0.0027179
10142	East End Mutual Electric	0.0003998	0.0003970	0.0003953
10144	Eatonville, City of	0.0004914	0.0004879	0.0004854
10156	Elmhurst Mutual P & L	0.0047975	0.0047636	0.0047429
10157	Emerald PUD	0.0074345	0.0073820	0.0073499
10158	Energy Northwest	0.0003356	0.0003332	0.0003316
10170	Eugene Water & Electric Board	0.0368066	0.0371030	0.0369419
10172	U.S. Airforce Base, Fairchild	0.0007718	0.0007733	0.0007731
10173	Fall River Elec Coop	0.0049302	0.0048954	0.0048742
10174	Farmers Elec Coop	0.0000754	0.0000749	0.0000746
10177	Ferry County PUD #1	0.0014298	0.0014260	0.0014262
10179	Flathead Elec Coop	0.0248256	0.0246503	0.0245433
10183	Franklin County PUD #1	0.0174636	0.0173403	0.0172650
10186	Glacier Elec Coop	0.0027360	0.0027167	0.0027046
10190	Grant County PUD #2	0.0007725	0.0007671	0.0007638
10191	Grays Harbor PUD #1	0.0188547	0.0187217	0.0186447
10197	Harney Elec Coop	0.0033860	0.0033621	0.0033475
10202	Hood River Elec Coop	0.0019492	0.0019355	0.0019271
10203	Idaho County L & P	0.0009247	0.0009181	0.0009141
10204	Idaho Falls Power	0.0118392	0.0117556	0.0117045
10209	Inland P & L	0.0156092	0.0154990	0.0154317
10230	Kittitas County PUD #1	0.0014438	0.0014336	0.0014274
10231	Klickitat County PUD #1	0.0054554	0.0054168	0.0053933
10234	Kootenai Electric Coop	0.0075894	0.0075359	0.0075031

BPA Customer ID	Customer Name	Modified TOCAs		
		FY2026	FY2027	FY2028
10235	Lakeview L & P (WA)	0.0045118	0.0044889	0.0044781
10236	Lane County Elec Coop	0.0043309	0.0043004	0.0042817
10237	Lewis County PUD #1	0.0169250	0.0168055	0.0167325
10239	Lincoln Elec Coop (MT)	0.0020835	0.0020688	0.0020598
10242	Lost River Elec Coop	0.0014176	0.0014076	0.0014015
10244	Lower Valley Energy	0.0128036	0.0127132	0.0126580
10246	Mason County PUD #1	0.0013374	0.0013280	0.0013222
10247	Mason County PUD #3	0.0118945	0.0118105	0.0117592
10256	Midstate Elec Coop	0.0069564	0.0069073	0.0068773
10258	Mission Valley	0.0056479	0.0056080	0.0055836
10259	Missoula Elec Coop	0.0040158	0.0039874	0.0039701
10260	Modern Elec Coop	0.0039115	0.0038839	0.0038671
10273	Nespelem Valley Elec Coop	0.0008752	0.0008690	0.0008653
10278	Northern Lights	0.0053466	0.0053088	0.0052858
10279	Northern Wasco County PUD	0.0096379	0.0095698	0.0095283
10284	Ohop Mutual Light Company	0.0015933	0.0015820	0.0015752
10285	Okanogan County Elec Coop	0.0009715	0.0009646	0.0009604
10286	Okanogan County PUD #1	0.0068322	0.0067840	0.0067546
10288	Orcas P & L	0.0036808	0.0036549	0.0036390
10291	Oregon Trail Coop	0.0117834	0.0117002	0.0116494
10294	Pacific County PUD #2	0.0054059	0.0053678	0.0053444
10304	Parkland L & W	0.0020070	0.0019972	0.0019935
10306	Pend Oreille County PUD #1	0.0022596	0.0022436	0.0022584
10307	Peninsula Light Company	0.0103067	0.0102465	0.0102135
10326	U.S. Naval Base, Bremerton	0.0042896	0.0042682	0.0042588
10331	Raft River Elec Coop	0.0054469	0.0054085	0.0053850
10333	Ravalli County Elec Coop	0.0027553	0.0027359	0.0027240
10338	Riverside Elec Coop	0.0003530	0.0003505	0.0003490
10342	Salem Elec Coop	0.0057578	0.0057171	0.0056923
10343	Salmon River Elec Coop	0.0017403	0.0017280	0.0017288
10349	Seattle City Light	0.0739838	0.0754925	0.0770789
10352	Skamania County PUD #1	0.0023671	0.0023504	0.0023402
10354	Snohomish County PUD #1	0.1141962	0.1148088	0.1153544
10360	Southside Elec Lines	0.0010067	0.0009996	0.0009953
10363	Springfield Utility Board	0.0132943	0.0132285	0.0131995
10369	Surprise Valley Elec Coop	0.0024453	0.0024281	0.0024175
10370	Tacoma Public Utilities	0.0495764	0.0482296	0.0477161

BPA Customer ID	Customer Name	Modified TOCAs		
		FY2026	FY2027	FY2028
10371	Tanner Elec Coop	0.0016418	0.0016302	0.0016231
10376	Tillamook PUD #1	0.0081747	0.0082042	0.0082431
10378	Coulee Dam, City of	0.0003009	0.0002987	0.0002974
10379	Steilacoom, Town of	0.0006812	0.0006792	0.0006779
10388	Umatilla Elec Coop	0.0168492	0.0167303	0.0166576
10391	United Electric Coop	0.0044611	0.0044296	0.0044103
10406	U.S. DOE Albany Research Center	0.0000682	0.0000677	0.0000674
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002272	0.0002256	0.0002246
10409	U.S. Naval Submarine Base, Bangor	0.0030389	0.0030175	0.0030044
10426	U.S. DOE Richland Operations Office	0.0057758	0.0060806	0.0061767
10434	Vera Irrigation District	0.0040412	0.0040127	0.0039953
10436	Vigilante Elec Coop	0.0028502	0.0028301	0.0028178
10440	Wahkiakum County PUD #1	0.0007449	0.0007396	0.0007364
10442	Wasco Elec Coop	0.0019409	0.0019293	0.0019228
10446	Wells Rural Elec Coop	0.0127284	0.0133401	0.0138146
10448	West Oregon Elec Coop	0.0012621	0.0012532	0.0012478
10451	Whatcom County PUD #1	0.0039931	0.0039649	0.0039477
10482	Umpqua Indian Utility Cooperative	0.0003978	0.0003950	0.0003935
10502	Yakama Power	0.0027833	0.0027642	0.0027522
13927	Kalispel Tribe Utility	0.0006062	0.0006020	0.0005993
10597	Hermiston, City of	0.0019201	0.0019117	0.0019034
10706	Port of Seattle - SETAC In'tl. Airport	0.0024905	0.0024729	0.0024618
11680	Weiser, City of	0.0009418	0.0009352	0.0009311
12026	Jefferson County PUD #1	0.0067223	0.0066749	0.0066459
10312	Port Townsend Paper	0.0016276	0.0016161	0.0016091
10197	New Resource Load	0.0001023	0.0028728	0.0037296
10298	PNGC Aggregate	0.1573140	0.1569120	0.1567705

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SECTION III. DEFINITIONS

1. Ancillary Services

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

a. Scheduling, System Control, and Dispatch
b. Reactive Supply and Voltage Control from Generation Sources
c. Regulation and Frequency Response
d. Energy Imbalance
e. Operating Reserve – Spinning
f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. Balancing Authority Area

See definition in Control Area.

3. Billing Factor

The Billing Factor is the quantity to which the rate specified in the rate schedule is applied. When the rate schedule includes rates for several products, there may be a Billing Factor for each product.

4. Control Area

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. Control Area Services

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations.

Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

a. Regulation and Frequency Response Service
b. Generation Imbalance Service
c. Operating Reserve – Spinning Reserve Service
d. Operating Reserve – Supplemental Reserve Service
e. Variable Energy Resource Balancing Service
f. Dispatchable Energy Resource Balancing Service

6. Daily Service

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.

7. Direct Assignment Facilities

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA for the sole use and benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Federal Energy Regulatory Commission policy. Direct Assignment Facilities shall be specified in the service agreement that governs service to the Transmission Customer.

8. Direct Service Industry (DSI) Delivery

The DSI Delivery segment consists of equipment necessary to deliver power to DSI customers at low voltages (i.e., 6.9 or 13.8 kV).

9. Dispatchable Energy Resource

For purposes of the ACS rate schedule, a Dispatchable Energy Resource is any non-federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

10. Dynamic Schedule

The definition of a Dynamic Schedule is provided in Section 1.30 of the Open Access Transmission Tariff.

11. Dynamic Transfer

The definition of a Dynamic Transfer is provided in Section 1.30 of the Open Access Transmission Tariff.

12. Eastern Intertie

The Eastern Intertie is the segment of the FCRTS for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

13. EIM Measured Demand

Includes 1) EIM Metered Demand, plus 2) e-Tagged export volumes from the BPA BAA (excluding EIM Transfers).

14. EIM Metered Demand

Metered load volumes in BPA's BAA.

15. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

16. Federal Columbia River Transmission System

The Federal Columbia River Transmission System (FCRTS) is the transmission facilities of the Federal Columbia River Power System, which include all

transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

17. Federal System

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

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability ("BPA's loads" do not include any of the loads of any BPA customer that are served by a non-federal generating resource purchased or owned directly by such customer that may be scheduled by BPA);
b. that BPA may use under contract or license; or
c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

18. Fifteen Minute Market (FMM)

The definition of FMM is provided in the MO Tariff.

19. Generation Imbalance

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

20. Generation Imbalance Service

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

21. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the period beginning with the hour ending 7 a.m. through hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable), except for holidays recognized by NERC.

22. Hourly Non-Firm Service

Hourly Non-firm Service is non-firm transmission service under Part II of the Open Access Transmission Tariff in hourly increments.

23. Integrated Demand

Integrated Demand is the quantity derived by mathematically "integrating" kilowatthour deliveries over a 60-minute period. For one-way Dynamic Schedules, demand is integrated on a rolling 10-minute basis.

24. Instructed Imbalance Energy (IIE)

A type of Imbalance Energy that occurs when changes are made to a resource, Interchange, or (if applicable) Intrachange schedule after the submission of the financially binding Transmission Customer Base Schedule. IIE will be settled at either the Fifteen Minute Market (FMM) or Real-Time Dispatch (RTD) price at the applicable Price Node (PNode) depending on the nature and timing of the imbalance.

25. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the period beginning with the hour ending 11 p.m. through 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 considers as LLH six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that a holiday falls on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If a holiday falls on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

26. 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 EIM.

27. Locational Marginal Price (LMP)

The marginal cost ($/MWh) of serving the next increment of demand at that PNode consistent with existing transmission constraints and the performance characteristics of resources.

28. Long-Term Firm Point-to-Point (PTP) Transmission Service

Long-Term Firm Point-to-Point Transmission Service is Firm Point-to-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of one year or more.

29. Measured Demand

The Measured Demand is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA under the applicable transmission rate schedule. If transmission service to a point of delivery or from a point of receipt is provided under more than one rate schedule, the portion of the measured quantities assigned to any rate schedule shall be as specified by contract. The portion of the total Measured Demand so assigned shall be the Measured Demand for transmission service for each transmission rate schedule.

30. Metered Demand

Except for Dynamic Schedules, the Metered Demand in kilowatts will be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered (received) for a transmission customer:

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

Such largest Integrated Demand shall be determined from measurements made in accord 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.

For one-way Dynamic Schedules, the Metered Demand in kilowatts will be the largest 10-minute moving average of the load (generation) at the point of delivery (receipt). The 10-minute moving average will be assigned to the hour in which the 10-minute period ends. For two-way Dynamic Schedules, the Metered Demand in kilowatts will be the largest instantaneous value of the Dynamic Schedule during the hour.

31. Montana Intertie

The Montana Intertie is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

32. Monthly Services

Monthly Service is service that starts at 00:00 on any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

33. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the peak loading on the Federal Transmission System during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of federal and non-federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.

34. Network

The Network consists of facilities that transmit power from federal and non-federal generation sources, from interconnections with other utilities, or from the interties, to the load centers of BPA's transmission customers in the Pacific Northwest, to interconnections with other utilities, or to other segments (*e.g.*, an intertie or delivery segment).

35. Network Integration Transmission (NT) Service

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

36. Network Load

Network Load is the load that a Network Customer designates for Network Integration Transmission Service under Part III of the Open Access Transmission Tariff. The Network Customer's Network Load will include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for

any Point-to-Point Transmission Service that may be necessary for such non-designated load.

37. Network Upgrades

Network Upgrades are modifications or additions to transmission-related facilities that support the BPA Transmission System for the general benefit of all users of such Transmission System.

38. Non-Firm Point-to-Point (PTP) Transmission Service

Non-Firm Point-to-Point Transmission Service is Point-to-Point Transmission Service under the Open Access Transmission Tariff that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption as set forth in Section 14.7 under Part II of the Tariff. Non-Firm PTP Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

39. Operating Reserve – Spinning Reserve Service

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. Operating Reserve – Supplemental Reserve Service

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. Operating Reserve Requirement

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

42. Point of Delivery (POD)

A Point of Delivery is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to Section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by BPA will be made available tothe Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other BPA transmission service agreements. The Point(s) of Delivery will be specified in the Service Agreement for Long-Term Firm Point-to- Point Service, Network Integration Transmission Service, and other BPA transmission services.

43. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected. This term is used in certain pre-Open Access Transmission Tariff service agreements and has the same meaning as "Point of Integration" and "Point of Receipt."

44. Point of Receipt (POR)

A Point of Receipt is a point of interconnection on the BPA Transmission System where capacity and energy will be made available to BPA by the Delivering Party under Parts II and III of the Open Access Transmission Tariff. The Point(s) of Receipt will be specified in the Service Agreement for Long-Term Firm Point-to- Point Service, Network Integration Transmission Service, and other BPA transmission services.

45. Pricing Node (PNode)

A single network node or subset of network nodes where a physical injection or withdrawal is modeled by the MO and for which the MO calculates an LMP that is used for financial settlements by the MO and the BPA EIM Entity.

46. Ratchet Demand

The Ratchet Demand in kilowatts or kilovars is the maximum demand established during a specified period of time during or prior to the current billing period. The Ratchet Demand will be the maximum demand established during the previous 11 billing months. If a Transmission Demand has been decreased pursuant to the terms of the transmission agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

47. Reactive Power

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power Demand is expressed in kilovars or kVAr, and Reactive Power Energy is expressed in kilovarhours or kVArh.

48. Reactive Supply and Voltage Control from Generation Sources Service

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA. The Transmission Customer must purchase this service from BPA.

49. Real-Time Dispatch (RTD)

The definition of RTD is provided in the MO Tariff.

50. Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to

maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

51. Reliability Obligations

Reliability Obligations are the obligations that a party with resources or loads in the BPA Control Area must provide in order to meet minimum reliability standards.

Reliability Obligations will be determined consistent with applicable NERC, WECC, and NWPP standards. BPA offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

52. Reserved Capacity

Reserved Capacity is the maximum amount of capacity and energy that BPA agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity will be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to accommodate a) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or b) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The supplemental Control Area service response will always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

53. Scheduled Demand

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

54. Scheduling, System Control, and Dispatch Service

Scheduling, System Control, and Dispatch Service is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area.

This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from BPA.

55. Short-Term Firm Point-to-Point (PTP) Transmission Service

Short-Term Firm Point-to-Point Transmission Service is Firm Point-to-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of less than one year. Short-Term Firm Point-to-Point Transmission Service with a duration of less than one calendar day is sometimes referred to as Hourly Firm Point-to-Point Transmission Service.

56. Southern Intertie

The Southern Intertie is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500-kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500-kV AC line from Buckley Substation to Summer Lake Substation; and the 500-kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000-kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

57. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

58. Spinning Reserve Requirement

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

59. Station Control Error

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

60. Super Forecast Methodology

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

61. Supplemental Reserve Requirement

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area. The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

62. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

63. Transmission Customer

A Transmission Customer is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that a) executes a Service Agreement, or b) requests in writing that BPA file with the Commission a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. In addition, a Transmission Customer is an entity that has executed any other transmission service agreement with BPA.

64. Transmission Demand

Transmission Demand is the maximum amount of capacity BPA agrees to make available to transmit energy for the Transmission Customer over the BPA Transmission System between the Point(s) of Integration/Interconnection/Receipt and the Point(s) of Delivery.

65. Transmission Provider

A Transmission Provider, such as BPA, owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Open Access Transmission Tariff and other agreements.

66. Variable Energy Resource

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: a) is renewable; b) cannot be stored by the facility owner or operator; and c) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

67. Weekly Service

Weekly Service is service that starts at 00:00 on any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

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