

BP-22 Rate Proceeding

Initial Proposal

2022 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2022–2023)

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BONNEVILLE POWER ADMINISTRATION

**2022 TRANSMISSION, ANCILLARY, AND
CONTROL AREA SERVICE RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS**

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
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
COE	U.S. Army Corps of Engineers
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 Council)
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-III	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
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)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
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
KSI	key strategic initiative
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
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	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
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
NWPP	Northwest Power Pool
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)
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)
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-IIIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
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
USACE	U.S. Army Corps of Engineers
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
WSPP	Western Systems Power Pool

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TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES

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FPT-22.1

FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-20.1 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System (FCRTS). This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.911 \text{ kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-22 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES

1. Main Grid Distance	\$0.0814 per mile
2. Main Grid Interconnection Terminal	\$0.85/kW
3. Main Grid Terminal	\$0.94/kW
4. Main Grid Miscellaneous Facilities	\$4.64/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.8000 per mile
2. Secondary System Transformation	\$8.75/kW
3. Secondary System Intermediate Terminal	\$3.38/kW
4. Secondary System Interconnection Terminal	\$2.39/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS**A. Ancillary Services**

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

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. Transmission Cost Recovery Adjustment Clause

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

D. Transmission Reserves Distribution Clause

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

E. Transmission Financial Reserves Policy Surcharge

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

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FPT-22.3

FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-20.3 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System (FCRTS). This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. 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. FY 2022 Rates

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.712 \text{ kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-22 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES

1.	Main Grid Distance	\$0.0728 per mile
2.	Main Grid Interconnection Terminal	\$0.76/kW
3.	Main Grid Terminal	\$0.84/kW
4.	Main Grid Miscellaneous Facilities	\$4.15/kW

SECONDARY SYSTEM CHARGES

1.	Secondary System Distance	\$0.7160 per mile
2.	Secondary System Transformation	\$7.83/kW
3.	Secondary System Intermediate Terminal	\$3.03/kW
4.	Secondary System Interconnection Terminal	\$2.14/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

B. FY 2023 Rates

The monthly charge per kilowatt shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

The Main Grid and Secondary System charges are calculated for each quarter according to the following formula:

$$\left(1 + \frac{GSR_q}{\$1.9110 \text{ kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-22 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES

1.	Main Grid Distance	\$0.0813 per mile
2.	Main Grid Interconnection Terminal	\$0.85/kW
3.	Main Grid Terminal	\$0.94/kW
4.	Main Grid Miscellaneous Facilities	\$4.63/kW

SECONDARY SYSTEM CHARGES

1.	Secondary System Distance	\$0.7992 per mile
2.	Secondary System Transformation	\$8.74/kW
3.	Secondary System Intermediate Terminal	\$3.38/kW
4.	Secondary System Interconnection Terminal	\$2.39/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS**A. Ancillary Services**

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. Failure To Comply Penalty

Customers taking transmission service under FPT agreements are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

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NT-22

NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-20 rate schedule. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities, including Conditional Firm (CF) Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. 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

\$2.080 per kilowatt per month

SECTION III. BILLING FACTOR

The monthly Billing Factor shall 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 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 shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that (1) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (2) 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:

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

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 = \$2.080 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 shall 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 shall 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 shall 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 shall 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 shall 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, 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 Surcharge, specified in GRSP II.I.

K. Delayed Loss Return Service Capacity Charge

Customers taking service under this rate schedule are subject to the Delayed Loss Return Service Capacity Charge, specified in GRSP II.J.

L. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.K.

PTP-22 POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-20 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. 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

\$1.751 per kilowatt per month

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

For each reservation, the rates shall not exceed:

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

a. Days 1 through 5 \$0.081 per kilowatt per day

b. Day 6 and beyond \$0.058 per kilowatt per day

2. Hourly Firm and Non-Firm Service

5.040 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 shall 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 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. shall 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. shall 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 shall receive a SDD. The SDD shall 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:

$$0.6 + (0.4 * \text{transmission distance} / 75).$$

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 shall be between the POR and the POD farthest from the POR.

If the customer redirects, 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 shall 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 shall 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 shall 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, 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 Surcharge, specified in GRSP II.I.

N. Delayed Loss Return Service Capacity Charge

Customers taking service under this rate schedule are subject to the Delayed Loss Return Service Capacity Charge, specified in GRSP II.J.

O. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.K.

IS-22

SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-20 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 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

\$1.188 per kilowatt per month

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

For each reservation, the rates shall 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

10.930 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 GSRPs. 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 shall 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 shall 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. shall 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. shall 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 shall 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 shall 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, 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 Surcharge, specified in GRSP II.I.

L. Delayed Loss Return Service Capacity Charge

Customers taking service under this rate schedule are subject to the Delayed Loss Return Service Capacity Charge, specified in GRSP II.J.

M. Financial For Inaccuracy Penalty Charge

Customers taking service under this rate schedule are subject to the Financial for Inaccuracy Penalty Charge, specified in GRSP II.K.

IM-22

MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-20 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. 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

\$0.518 per kilowatt per month

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

For each reservation, the rates shall not exceed:

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

a. Days 1 through 5 \$0.024 per kilowatt per day

b. Day 6 and beyond \$0.017 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.490 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 shall 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. shall 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. shall 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 shall 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 shall 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, 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 Surcharge, specified in GRSP II.I.

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UFT-22

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-20 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 shall 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 shall 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 shall 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 shall 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 shall 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-22 ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-20 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 shall 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 shall 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-22

TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-20 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 shall 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 annual costs of the facilities, but in any given year there may be a surplus or a deficit. Such surplus or deficit for any year shall 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

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

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: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to Section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result 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 (1) 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 (2) 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 500 kV 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 (1) the sum of all Capacity Requirements (*CR*) specified in transmission agreements described in Section I and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall 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 (1) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and (2) 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 shall be zero.

RC-22

REGIONAL COMPLIANCE ENFORCEMENT AND REGIONAL COORDINATOR RATES

SECTION I. AVAILABILITY

This schedule supersedes the RC-20 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

0.040 mills per kilowatthour

B. Regional Coordinator Rate

0.040 mills per kilowatthour

SECTION III. BILLING FACTORS

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

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OS-22 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-20 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 Resources Firm Power rate, for the charges to BPA Power Services under Section II.C.

The Oversupply Charge shall collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2022, through September 30, 2023. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2022-2023 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) shall be:

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

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 shall be used for power dynamically transferred out of BPA's Balancing Authority Area.

$\sum \text{Scheduled Generation}$ = 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 shall be billed to customers purchasing under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate schedules using a Modified TOCA. The charge for each such customer shall 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.N.

SECTION III. BILLING

A. Oversupply Charge

The Oversupply charge shall 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, shall 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 shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall 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) shall be separately included on each applicable customer's transmission bill.

IE-22 EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-20 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 shall not exceed 1.490 mills per kilowatthour.

SECTION III. BILLING FACTOR

The Billing Factor shall 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.

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ACS-22

ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-20 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff (Tariff) 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 of 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 shall 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

Energy Imbalance Market (EIM) Service is used to meet the Energy Imbalance and Generation Imbalance 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 Service (Tariff Schedule 4E)
 - b. Generator Imbalance 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. Rolled In Charges
6. 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 shall not exceed \$0.371 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed \$0.314 per kilowatt per month.

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

For each reservation, the rates shall not exceed:

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

(a) Days 1 through 5 \$0.014 per kilowatt per day

(b) Day 6 and beyond \$0.010 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.900 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) shall 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 shall 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 shall be the Reserved Capacity, and the following shall 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 Open Access Transmission Tariff 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. shall equal the NT rate Billing Factor determined pursuant to Section III of the Network Integration Rate Schedule (NT-22).

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 shall 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 2021, 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) shall be calculated to three decimal places. Rates for Hourly Service (Section b.(2), below) shall 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), shall not exceed:

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

Where:

bd = 501,314 kW = Average of forecasted FY 2022 and FY 2023 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, 2021, 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, 2021 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 shall not exceed:

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

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

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

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

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

The rate shall not exceed:

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

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) shall 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 shall 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 shall be the Reserved Capacity, and the following shall 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 Open Access Transmission Tariff 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. shall equal the NT rate Billing Factor determined pursuant to Section III of the Network Integration Rate Schedule (NT-22).

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 shall 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. Regulation and Frequency Response 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 shall not exceed 0.538 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 Energy Imbalance Service from BPA when such services are provided pursuant to Schedule 4 of the BPA Tariff.

Energy Imbalance Service under Schedule 4 is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA BAA 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 (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (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 greater 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) taken by the Transmission Customer is less than the 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 (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW,

whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 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 (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 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 shall 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 shall 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 Web site 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 Energy Imbalance Service shall 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 shall not exceed 11.438 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 shall be 13.154 mills per kilowatthour.

For energy delivered, the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 shall not exceed 7.055 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 shall be 8.113 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall 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 Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response 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 shall not exceed 0.538 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 Service is provided for in an interconnection agreement or other arrangement. The rates below shall apply when such services are provided pursuant to Schedule 9 of the BPA Tariff.

Generation Imbalance 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 (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (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) 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 incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 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 shall 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 shall 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 Web site 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 shall not exceed 11.438 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 shall be 13.154 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 shall not exceed 7.055 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 shall be 8.113 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 or Balancing Service) 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). Variable Energy Resource Balancing Service 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 Balancing Service is the applicable rate in Section 2.a. or 2.b, below, plus Direct Assignment Charges under Section 3 and Intentional Deviation Penalty Charges under Section 4.

a. Balancing Service Rates For Wind Resources

Customers taking Balancing Service 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.

- | | | |
|-----|-------------------------|--------------------------------|
| (1) | Regulating Reserves | \$0.407 per kilowatt per month |
| (2) | Non-Regulating Reserves | \$0.527 per kilowatt per month |

b. Balancing Service Rates For Solar Resources

Customers taking Balancing Service 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.

- | | | |
|-----|-------------------------|--------------------------------|
| (1) | Regulating Reserves | \$0.420 per kilowatt per month |
| (2) | Non-Regulating Reserves | \$0.282 per 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 kW 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 kW.
- (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 Balancing Service, including by contractual arrangements for third-party supply.

3. Direct Assignment Charges

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service 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 Variable Energy Resource Balancing Service; or
- b. the customer has a projected generator interconnection date after FY 2023, but chooses to interconnect during the FY 2022–2023 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 \$0.239 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.

4. 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 service is the charge determined by applying the rates in Section 1 below, plus Direct Assignment Charges in Section 4 below.

1. Rates

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

- a. Incremental Reserves 34.797 mills per kW maximum hourly deviation
- b. Decremental Reserves 2.482 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.
- 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.

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 mHz shall 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 Dispatchable Energy Resource Balancing Service to the customer if:

- a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or
- b. a customer has a projected generator interconnection date after FY 2023 but chooses to interconnect during the FY 2022-2023 rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2022-2023 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 \$0.239 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 shall 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 in order to integrate new uses of technology, such as a solar project coupled with a co-located battery. The goal of the pilot is to reduce the project's balancing reserve capacity burden placed on the BPA BAA. In place of any normally applicable Regulation and Frequency Response, 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 capacity rate components:

- | | | |
|-----|-------------------------|--------------------------|
| (a) | Regulating Reserves | \$0.299 per kilowatt-day |
| (b) | Non-Regulating Reserves | \$0.239 per kilowatt-day |
| (c) | DEC Balancing Reserves | \$0.023 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), and shall not exceed the total cost of the normally applicable Regulation and Frequency Response, 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 shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, resulting in the pilot adding to rather than reducing the Station Control Error of the project.

SECTION IV. ENERGY IMBALANCE MARKET SERVICES AND RATES

The rates below shall apply when Energy Imbalance and Generation Imbalance services are provided pursuant to Tariff Schedules 4E and 9E of the BPA Tariff.

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

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

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

A Transmission Customer shall be charged or paid for Energy Imbalance 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 Uninstructed Imbalance Energy (UIE) for the period of the deviation at the applicable 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 Energy Imbalance Service shall be subject to the Persistent Deviation Penalty Charge for UIE pursuant to GRSP II.M.2.

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

a. Generation Imbalance 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 Generator Imbalance 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. Generation Imbalance 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 shall 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 Generator Imbalance 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 Generation Imbalance Service shall 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 Generator Imbalance 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 under 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 Generator Imbalance 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 BP, then the FMM-IIE and RTD-IIE associated with such Intrachange shall be settled with the resource in accordance with Section IV.B.2 of this section.

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 FMM or RTD market interval. Transmission Customers with Interchange Imbalance shall be assessed IIE at either the Fifteen-Minute Market (FMM) Locational Marginal Price (LMP), the Real-Time Dispatch (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 shall 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 shall 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 shall 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 BP. Intrachange Imbalance shall 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 shall 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 shall 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 shall 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 shall 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 BP.

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 underscheduling load shall 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 shall 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 shall 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 shall 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 shall 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 shall 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 shall 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 shall 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 shall be sub-allocated to Transmission Customers on the basis of EIM Measured Demand.

E. 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 shall be rolled in and recovered through base Transmission rates.

F. 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 shall 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, the Transmission Reserves Distribution Clause, and the Transmission Financial Reserves Policy Surcharge, specified in GRSPs II.G, II.H, and II.I.

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, 2021. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-22 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-20 rate schedules, which became effective October 1, 2019, to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (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-22 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 shall prevail.

C. Notices

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

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 shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall 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) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall 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 thirty (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 Commission policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Delivery Charge

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery and Utility Delivery facilities and equipment.

1. Rates

a. DSI Delivery

Use-of-Facilities (UFT-22) Rate, Section III

b. Utility Delivery

\$1.712 per kilowatt (kW) per month

2. Billing Factor

a. Utility Delivery

The monthly Billing Factor for the Utility Delivery rate in Section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as providing Utility Delivery service.

The monthly Utility Delivery Billing Factor shall be adjusted for customers that pay for Utility Delivery service under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities and equipment used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

3. Adjustments, Charges, and Other Rate Provisions

a. Transmission Cost Recovery Adjustment Clause

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

b. Transmission Reserves Distribution Clause

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

c. Transmission Financial Reserves Policy Surcharge

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

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 Failure to Comply Penalty Charge shall be the greater of 500 mills per kWh or 150 percent of an hourly energy index in the Pacific Northwest.

If no adequate hourly index exists, an alternative index will be used. At least 30 days prior to the use of such index BPA will post on its Transmission Rates website the name of the index to be used. 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.

2. Billing Factor

The Billing Factor for the Failure to Comply Penalty Charge shall 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 Open Access Transmission Tariff 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 Open Access Transmission Tariff 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. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history 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 shall 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, shall 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 shall 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 shall 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 shall 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 shall 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 shall be the lesser of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 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 shall 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;
- (2) could not have been avoided by the exercise of reasonable care; and
- (3) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

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 shall 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 shall 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 shall 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 shall 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. shall 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-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

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)
2021	2022	\$0	\$45	\$100
2022	2023	\$0	\$45	\$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, 2021, BPA will complete the calculation of Transmission RFR as of the end of FY 2021, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA will complete the calculation of Transmission RFR as of the end of FY 2022, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2023.

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 determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Transmission Dividend Distribution (Transmission DD), distributions to customers, or any other Transmission-specific purposes determined by the Administrator.

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

- Network Integration Rate (NT-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

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. If the Administrator determines that all or part of the Transmission RDC Amount will be applied to a Transmission DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission RDC Amount

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

The Transmission RDC Amount is the amount of Transmission RFR that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a

Transmission DD, distribute to customers, or any other Transmission-specific purposes determined by the Administrator. The Transmission RDC Amount will be the smallest of Transmission RFR minus the Transmission RDC Threshold, BPA RFR minus the BPA RDC Threshold, or the Transmission RDC Cap.

Table B
Transmission RDC Annual Thresholds and Caps
(dollars in millions)

Transmission RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Transmission RFR Threshold	Maximum RDC Amount (Cap)
2021	2022	\$210	\$200
2022	2023	\$210	\$200

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
2021	2022	\$611
2022	2023	\$611

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 10 month period of December 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, 2021, BPA shall complete the calculation of Transmission RFR and BPA RFR as of the end of FY 2021, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Transmission RFR and BPA RFR as of the end of FY 2022, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2023.

If the Transmission RDC triggers, BPA will notify customers of the preliminary Transmission RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Transmission purposes, or reduce rates, 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, and if applicable, the Transmission DD Credit Amount and the Transmission DD Credit percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission RDC amount as soon as practicable, but in no case later than December 15 of each applicable 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-22)
- Point-to-Point Rate (PTP-22)
- Formula Power Transmission Rate (FPT-22.1)
- Southern Intertie Point-to-Point Rate (IS-22)
- Scheduling, System Control, and Dispatch Rate (ACS-22)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-22)

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
2021	2022	\$105	\$45	\$15
2022	2023	\$105	\$45	\$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, 2021, BPA shall complete the calculation of Transmission RFR as of the end of FY 2021, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Transmission RFR as of the end of FY 2022, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2023.

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. Delayed Loss Return Service Capacity Charge

This charge applies to a Transmission Customer that elects In-Kind Loss Return Service or Slice Output Loss Return Service where the Transmission Customer returns real power loss obligations with physical delivery of in-kind power 168 hours after the obligation is incurred.

1. Rate

The rate shall not exceed \$2.63 mills per kWh.

2. Billing Factors

The Billing Factor for a Transmission Customer taking PTP transmission service on the Network or Southern Intertie segments (PTP and IS) shall be the sum of the scheduled energy for each hour of the month, in kWh, multiplied by the applicable loss factor specified in the Tariff, Schedule 11.

The Billing Factor for a Transmission Customer taking NT transmission service on the Network Segment (NT) shall be the sum of non-federal deliveries and/or Slice Output that is scheduled for each hour of the month, in kWh, multiplied by the applicable loss factor specified in the Tariff, Schedule 11.

3. Other Provisions

If real power loss obligations are waived under Attachment P of the Tariff, a Transmission Customer shall not be subject to the Delayed Loss Return Service Capacity Charge for hours in which losses are not returned due to the waiver.

K. Financial for Inaccuracy Penalty Charge

The Financial for Inaccuracy Penalty Charge (FFI Penalty Charge) applies to a Transmission Customer that elects In-Kind Loss Return Service when the Customer returns a different amount of power than its real power loss obligation or does not timely settle its loss obligation.

1. Rates

a. Energy Price

The Energy Price for the FFI Penalty Charge will differ depending on whether BPA is a participant in the Western Energy Imbalance Market (EIM).

(1) Energy Price when BPA is not an EIM Participant.

If BPA is not a participant in the EIM, then the Energy Price will be the applicable average hourly Powerdex Mid-C Index price for firm power for the hour in which the loss occurred. In the event the hourly Powerdex Mid-C price index is no longer a reliable price index, the index will be replaced by an applicable new hourly energy index at a hub at which Northwest parties can trade between October 1, 2021, and September 30, 2023. BPA will provide notice of such a change as soon as practicable.

(2) Energy Price when BPA is an EIM Participant.

If BPA is a participant in the EIM, then the Energy Price will be the applicable hourly average Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred.

b. Under Delivery Event (UDE)

For each hour that the Transmission Customer returns less energy than its real power loss obligation, the FFI penalty rates shall be:

(1) UDE Capacity Rate: 2.81 mills per kilowatthour

(2) UDE Energy Rate: the greater of \$0 or 125 percent of the Energy Price.

c. Over Delivery Event (ODE)

For each hour that the Transmission Customer returns more energy than its real power loss obligation and the Energy Price is less than \$0 per MWh, the FFI penalty rates shall be:

(1) ODE Capacity Rate: 2.81 mills per kilowatthour

(2) ODE Energy Rate: 125 percent of the absolute value of the Energy Price

The ODE Energy Rate shall not be assessed when the Transmission Customer returns more energy than its real power loss obligation and the Energy Price is equal to or greater than \$0 per MWh.

2. Billing Factors

a. Under Delivery Event

The Billing Factor (in kWh) for the UDE rates shall be for each hour:

Customer's Real Power Loss Obligation

Minus

The quantity of loss returns provided by the customer.

b. Over Delivery Event

The Billing Factor (in kWh) for the ODE rates shall be for each hour:

The quantity of loss returns provided by the customer

Minus

Customer's Real Power Loss Obligation

3. Other Provisions

BPA will exempt a Transmission Customer from the FFI Penalty Charge during times of BAA or Transmission Provider reliability adjustments to real power loss obligations.

4. Waiver or Reduction of Charge

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

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the Transmission Customer's history of incurring FFI Penalty 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-22 Variable Energy Resources Balancing Service (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 megawatt-hour (MWh).

An Intentional Deviation event occurs when:

$$ABS(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) > 1$$

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

3. Billing Factor

The Billing Factor in MWh shall be:

$$ABS(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) - 1$$

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

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

$$ABS(\text{Station Control Error}) \leq ABS(\text{Intentional Deviation Measurement Value Error}) + 1 \text{ MW}$$

Where:

$ABS(\text{Intentional Deviation Measurement Value Error})$ = 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 Energy Imbalance Market 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. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Intentional Deviation Penalty Charge 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 twelve 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 twenty-four 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 Uninstructed Imbalance Energy.

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 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. For Participating Resources in the Energy Imbalance Market the charge is the greater of (i) 25 percent of the highest LMP at the closest point of interconnection during the period of penalty, or (ii) 100 mills per kilowatthour minus the

highest 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 charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant ACS II.B or ACS.IV.B.2.

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 Energy Imbalance 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 twelve 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 twenty-four consecutive hours or more in the same direction.

For Energy Imbalance Service pursuant to ACS IV.B.1, positive or negative deviations will be based on the measurement value used for determining Uninstructed Imbalance Energy (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 (i) 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.B.1, or (ii) 100 mills per kilowatthour.

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 charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to ACS II.D or IV.B.1.

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 Generation Imbalance Service, the rate under Section 1.b above shall apply, and for Energy Imbalance 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 (i) 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 (ii) the Persistent Deviation was caused by extraordinary circumstances.

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

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10005	Alder Mutual	0.0000817	0.0000813
10015	Asotin County PUD #1	0.0000855	0.0000851
10024	Benton County PUD #1	0.0300127	0.0298783
10025	Benton REA	0.0088957	0.0088559
10027	Big Bend Elec Coop	0.0091246	0.0090838
10029	Blachly Lane Elec Coop	0.0026267	0.0026149
10044	Canby, City of	0.0030283	0.0030148
10046	Central Electric Coop	0.0122048	0.0121501
10047	Central Lincoln PUD	0.0233614	0.0232568
10055	Albion, City of	0.0000594	0.0000591
10057	Ashland, City of	0.0031226	0.0031086
10059	Bandon, City of	0.0011390	0.0011339
10061	Blaine, City of	0.0013041	0.0012983
10062	Bonnors Ferry, City of	0.0007931	0.0007896
10064	Burley, City of	0.0020971	0.0020878
10065	Cascade Locks, City of	0.0003545	0.0003530
10066	Centralia, City of	0.0036340	0.0036177
10067	Cheney, City of	0.0023585	0.0023479
10068	Chewelah, City of	0.0004047	0.0004037
10070	Declo, City of	0.0000535	0.0000533
10071	Drain, City of	0.0002855	0.0002842
10072	Ellensburg, City of	0.0035760	0.0035600
10074	Forest Grove, City of	0.0039785	0.0039607
10076	Heyburn, City of	0.0007182	0.0007150
10078	McCleary, City of	0.0005543	0.0005518
10079	McMinnville, City of	0.0126935	0.0126693
10080	Milton, Town of	0.0010724	0.0010680
10081	Milton-Freewater, City of	0.0014417	0.0014354
10082	Minidoka, City of	0.0000148	0.0000148
10083	Monmouth, City of	0.0012471	0.0012415
10086	Plummer, City of	0.0005882	0.0005856
10087	Port Angeles, City of	0.0087954	0.0087560
10089	Richland, City of	0.0154860	0.0154167
10091	Rupert, City of	0.0014050	0.0013987
10094	Soda Springs, City of	0.0004529	0.0004509
10095	Sumas, Town of	0.0005432	0.0005408
10097	Troy, City of	0.0003039	0.0003025
10101	Clallam County PUD #1	0.0113365	0.0112857

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10103	Clark County PUD #1	0.0474905	0.0472778
10105	Clatskanie PUD	0.0129559	0.0129531
10106	Clearwater Power	0.0035606	0.0035447
10109	Columbia Basin Elec Coop	0.0018070	0.0017990
10111	Columbia Power Coop	0.0004768	0.0004743
10112	Columbia River PUD	0.0086094	0.0085875
10113	Columbia REA	0.0056204	0.0055952
10116	Consolidated Irrigation District #19	0.0000339	0.0000338
10118	Consumers Power	0.0068104	0.0067799
10121	Coos Curry Elec Coop	0.0060819	0.0060547
10123	Cowlitz County PUD #1	0.0710735	0.0743784
10136	Douglas Electric Cooperative	0.0027641	0.0027517
10142	East End Mutual Electric	0.0004007	0.0003989
10144	Eatonville, City of	0.0005023	0.0005000
10156	Elmhurst Mutual P & L	0.0048070	0.0047855
10157	Emerald PUD	0.0074492	0.0074159
10158	Energy Northwest	0.0003710	0.0003693
10170	Eugene Water & Electric Board	0.0355877	0.0356588
10172	U.S. Airforce Base, Fairchild	0.0008550	0.0008532
10173	Fall River Elec Coop	0.0049400	0.0049179
10174	Farmers Elec Coop	0.0000756	0.0000753
10177	Ferry County PUD #1	0.0013923	0.0013893
10179	Flathead Elec Coop	0.0248747	0.0247633
10183	Franklin County PUD #1	0.0174983	0.0174199
10186	Glacier Elec Coop	0.0028374	0.0028416
10190	Grant County PUD #2	0.0007741	0.0007706
10191	Grays Harbor PUD #1	0.0195657	0.0194781
10197	Harney Elec Coop	0.0033926	0.0033775
10202	Hood River Elec Coop	0.0019532	0.0019445
10203	Idaho County L & P	0.0009265	0.0009224
10204	Idaho Falls Power	0.0098507	0.0098134
10209	Inland P & L	0.0156402	0.0155701
10230	Kittitas County PUD #1	0.0014467	0.0014402
10231	Klickitat County PUD #1	0.0054662	0.0054417
10234	Kootenai Electric Coop	0.0076044	0.0075704
10235	Lakeview L & P (WA)	0.0047951	0.0047975
10236	Lane County Elec Coop	0.0042799	0.0042607
10237	Lewis County PUD #1	0.0164017	0.0163282
10239	Lincoln Elec Coop (MT)	0.0020876	0.0020782
10242	Lost River Elec Coop	0.0014204	0.0014140

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10244	Lower Valley Energy	0.0128290	0.0127715
10246	Mason County PUD #1	0.0013400	0.0013340
10247	Mason County PUD #3	0.0119181	0.0118648
10256	Midstate Elec Coop	0.0069702	0.0069390
10258	Mission Valley	0.0056589	0.0056336
10259	Missoula Elec Coop	0.0040237	0.0040057
10260	Modern Elec Coop	0.0039193	0.0039017
10273	Nespelem Valley Elec Coop	0.0008769	0.0008730
10278	Northern Lights	0.0053572	0.0053332
10279	Northern Wasco County PUD	0.0096570	0.0096138
10284	Ohop Mutual Light Company	0.0015147	0.0015080
10285	Okanogan County Elec Coop	0.0009735	0.0009691
10286	Okanogan County PUD #1	0.0068458	0.0068152
10288	Orcas P & L	0.0036881	0.0036716
10291	Oregon Trail Coop	0.0118068	0.0117540
10294	Pacific County PUD #2	0.0054166	0.0053924
10304	Parkland L & W	0.0020924	0.0020881
10306	Pend Oreille County PUD #1	0.0000000	0.0000000
10307	Peninsula Light Company	0.0106499	0.0106131
10326	U.S. Naval Base, Bremerton	0.0045418	0.0045214
10331	Raft River Elec Coop	0.0054578	0.0054333
10333	Ravalli County Elec Coop	0.0027606	0.0027483
10338	Riverside Elec Coop	0.0003537	0.0003521
10342	Salem Elec Coop	0.0057692	0.0057433
10343	Salmon River Elec Coop	0.0018783	0.0018699
10349	Seattle City Light	0.0663918	0.0673246
10352	Skamania County PUD #1	0.0023718	0.0023611
10354	Snohomish County PUD #1	0.1103245	0.1090982
10360	Southside Elec Lines	0.0010087	0.0010041
10363	Springfield Utility Board	0.0142429	0.0142142
10369	Surprise Valley Elec Coop	0.0024501	0.0024391
10370	Tacoma Public Utilities	0.0578761	0.0575211
10371	Tanner Elec Coop	0.0016451	0.0016377
10376	Tillamook PUD #1	0.0083545	0.0083171
10378	Coulee Dam, City of	0.0002937	0.0002930
10379	Steilacoom, Town of	0.0007108	0.0007110
10388	Umatilla Elec Coop	0.0168827	0.0168071
10391	United Electric Coop	0.0044699	0.0044499
10406	U.S. DOE Albany Research Center	0.0000683	0.0000680
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002278	0.0002267

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10409	U.S. Naval Submarine Base, Bangor	0.0030451	0.0030314
10426	U.S. DOE Richland Operations Office	0.0025608	0.0025493
10434	Vera Irrigation District	0.0040493	0.0040312
10436	Vigilante Elec Coop	0.0028557	0.0028429
10440	Wahkiakum County PUD #1	0.0007464	0.0007430
10442	Wasco Elec Coop	0.0019885	0.0019796
10446	Wells Rural Elec Coop	0.0142803	0.0142164
10448	West Oregon Elec Coop	0.0012645	0.0012589
10451	Whatcom County PUD #1	0.0040011	0.0039832
10482	Umpqua Indian Utility Cooperative	0.0004386	0.0004366
10502	Yakama Power	0.0027895	0.0027770
13927	Kalispel Tribe Utility	0.0005910	0.0005958
10597	Hermiston, City of	0.0019238	0.0019163
10706	Port of Seattle - SETAC In'tl. Airport	0.0025764	0.0025648
11680	Weiser, City of	0.0009437	0.0009395
12026	Jefferson County PUD #1	0.0067358	0.0067056
10007	Alcoa	0.0000000	0.0000000
10312	Port Townsend Paper	0.0018758	0.0018674
10298	PNGC Aggregate	0.0620971	0.0618189

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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. Dispatchable Energy Resource Balancing Service

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

13. 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.

14. EIM Measured Demand:

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

15. EIM Metered Demand:

Metered load volumes in BPA's BAA.

16. 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.

17. 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.

18. 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.

19. Fifteen Minute Market (FMM)

The definition of FMM is provided in the MO Tariff.

20. 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.

21. 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.

22. 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.

23. 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.

24. 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 ten-minute basis.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. Main Grid

As used in the FPT rate schedule, the Main Grid is that portion of the Network facilities with an operating voltage of 230 kV or more.

31. Main Grid Distance

As used in the FPT rate schedules, Main Grid Distance is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

32. Main Grid Interconnection Terminal

As used in the FPT rate schedules, Main Grid Interconnection Terminal refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

33. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, Main Grid Miscellaneous Facilities refers to switching, transformation, and other facilities of the Main Grid not included in other components.

34. Main Grid Terminal

As used in the FPT rate schedules, Main Grid Terminal refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

35. 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.

36. Metered Demand

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

37. Montana Intertie

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

38. 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.

39. 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.

40. 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).

41. Network Integration Transmission (NT) Service

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

42. 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 shall 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.

43. 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.

44. 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.

45. 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.

46. 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.

47. 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.

48. Persistent Deviation

A Persistent Deviation event is one or more of the following:

a. For Generation Imbalance Service only:

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 schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the 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 schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. For Energy Imbalance Service only:

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 schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

- (2) both 7.5 percent of the 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 schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
 - (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.
- c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

49. 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 to the 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 shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

50. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point.

51. 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.”

52. 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 shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

53. 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.

54. 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 shall 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.

55. 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.

56. 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.

57. Real-Time Dispatch (RTD)

The definition of RTD is provided in the MO Tariff.

58. 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.

59. 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 shall 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.

60. 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 shall 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 (i) 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 (ii) 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 shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

61. Scheduled Demand

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

62. 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.

63. Secondary System

As used in the FPT rate schedules, Secondary System is that portion of the Network facilities with an operating voltage greater than or equal to 69 kV and less than 230 kV.

64. Secondary System Distance

As used in the FPT rate schedules, Secondary System Distance is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

65. Secondary System Interconnection Terminal

As used in the FPT rate schedules, Secondary System Interconnection Terminal refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

66. Secondary System Intermediate Terminal

As used in the FPT rate schedules, Secondary System Intermediate Terminal refers to the first and last terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

67. Secondary Transformation

As used in the FPT rate schedules, Secondary Transformation refers to transformation from Main Grid to Secondary System facilities.

68. 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.

69. 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.

70. 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.

71. 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.

72. 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.

73. 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.

74. 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.

75. Total Transmission Demand

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

76. Transmission Customer

A Transmission Customer is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that (i) executes a Service Agreement, or (ii) 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.

77. 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.

78. 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.

79. Utility Delivery

The Utility Delivery segment consists of facilities and equipment that transform and deliver energy to a utility's distribution system at (or close to) the utility's prevailing distribution voltage.

80. Variable Energy Resource

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) 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.

81. Variable Energy Resource Balancing Service

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

82. 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.

