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

BP-26 Rate Proceeding

Final Proposal

Generation Inputs Study

BP-26-FS-BPA-06

July 2025

GENERATION INPUTS STUDY

Table of Contents

COMMONLY USED ACRONYMS AND SHORT FORMS

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

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
ELMP	Extended Locational Marginal Pricing
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
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
ISD	Incremental Standard Deviation
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
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
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)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement

RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
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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1. INTRODUCTION

BPA's generation assets provide energy and capacity that is necessary to support the transmission system and maintain reliability. The uses of the energy and capacity available to support the transmission system and maintain reliability are generally referred to as "generation inputs." For ratemaking purposes, the costs associated with generation inputs are allocated to transmission rates and recovered through the charges for BPA's Ancillary and Control Area Services.

1.1 Purpose of Study

This Study explains the determination of the forecast amount, cost allocation, and forecast revenues associated with generation inputs. The Study also describes the methodology used to set the Ancillary and Control Area Services rates that recover the generation input costs. The revenues that are forecast in the Study are applied in ratemaking as revenue credits to power rates. *See* Power Rates Study, BP-26-FS-BPA-01, § 9.3. The Ancillary and Control Area Services rates that are described in the Study are shown in the 2026 Transmission Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-26-A-01-AP02.

1.2 Summary of Study

Balancing reserve capacity is the capacity necessary for BPA's balancing services, which includes Regulation and Frequency Response Service, Variable Energy Resource Balancing Service (VERBS), and Dispatchable Energy Resource Balancing Service (DERBS). The methodology for deriving the forecast amount of balancing reserve capacity needed to provide these services and the allocation of reserves among each generation type and load is described in Section 2 of this Study. Section 3 details the methodology for determining the forecast need for capacity for Operating Reserve (Contingency Reserve) services. Section 4 of the Study contains the description of the design and calculation of the rates for BPA's Ancillary and Control Area Services.

A summary of the revenue forecast for supplying these generation inputs is shown in Table 1 in Generation Inputs Study Documentation, BP-26-FS-BPA-06A.

2. BALANCING RESERVE CAPACITY QUANTITY FORECAST

2.1 Introduction

2.1.1 Purpose of the Balancing Reserve Capacity Quantity Forecast

The Balancing Reserve Capacity Quantity Forecast estimates the planned amount of balancing reserve capacity needed for BPA to provide balancing services, including regulating and non-regulating reserves, during the rate period for Schedules 3 and 10 of BPA's Tariff. This forecast reflects the quality of service and the methodology for determining the total balancing reserve capacity for balancing services as defined in the Balancing Reserve Capacity Business Practice. The forecast described in this section focuses on the data inputs needed for the Balancing Reserve Capacity Business Practice methodology to forecast balancing services for the rate period, including the total balancing reserve capacity. Also, the forecast described in this section describes the methodology used to allocate the balancing reserve requirements to load and different types of generation to establish the rates for these services and the revenue credit to Power Services associated with providing the balancing reserve capacity for the rate period. *See* § 4; Power Rates Study, BP-26-FS-BPA-01, § 9.3.1 (Capacity Cost Methodology). For the BP-26 rate period, the amount of balancing reserves needed for the rate period is greater than what can be provided from the FCRPS.

2.1.2 Overview

As a balancing authority (BA), BPA must maintain load-resource balance in its Balancing Authority Area (BAA) at all times. All generators within the BPA BAA provide generation schedules to BPA that estimate the average amount of energy they expect to generate in the upcoming scheduling period (hour or 15-minute interval).

Transmission customers submit transmission schedules, identifying all energy to be transmitted across or within the BPA BAA in the upcoming scheduling period. BPA uses the transmission schedules to match generation inside the BPA BAA and imports of energy from other BAAs with loads served inside the BPA BAA and exports to other BAAs. The transmission schedules identified with each adjacent BAA are netted to determine interchange schedules. Also, BPA forecasts the average amount of load to be served in the BPA BAA in the upcoming hour, ensuring the summation of generation schedules will serve the forecasted load plus exports and minus imports.

The Automatic Generation Control (AGC) system regulates the output of specified Federal Columbia River Power System (FCRPS) generators or third-party providers of balancing reserves (BPA currently does not have any third-party providers of balancing reserves) in the BPA BAA in response to changes in load, generation, system frequency, and other factors to maintain the scheduled system frequency and scheduled interchanges with other BAAs. Schedules do not change when a generator deviates from its scheduled generation or a load deviates from the average hourly forecast. The BAA uses the specified FCRPS generation resources, assigned for balancing service and connected to the AGC system, to maintain within-hour load-resource balance in the BAA by offsetting differences between scheduled and actual generation and load, as measured by the Area Control Error (ACE) equation. If actual load increases or actual generation decreases compared to the amount scheduled, the AGC system increases (*inc*) output of balancing resources. If actual load decreases or actual generation increases compared to the amount scheduled, the AGC system decreases (*dec*) output of balancing resources. The cumulative *inc* and *dec* generation required to maintain within-hour load-resource balance forms the basis for the balancing reserve capacity that BPA must maintain to provide balancing services.

BPA's methodology for calculating the total balancing reserve capacity requirement is provided in the Balancing Reserve Capacity Business Practice. As explained in this business practice, BPA assumes a 99.7 percent planning standard for purposes of determining the total balancing reserve capacity requirement, the same standard used historically by BPA in past rate periods. BPA's balancing reserve capacity requirement consists of two components: regulating reserves and non-regulating reserves. Regulating reserves refer to the capacity necessary to provide for the continuous balancing of resources (generation and interchange) with load on a moment-to-moment basis. Non-regulating reserves refer to the capacity necessary to compensate for larger fluctuations in generation and load occurring over longer periods of time within the hour. The Balancing Reserve Capacity Quantity Forecast estimates the capacity needed to provide both of these components of the requirement.

The Balancing Reserve Capacity Quantity Forecast methodology is based primarily on a) a forecast of wind, solar, hydroelectric, and thermal projects expected to be online in the BPA BAA during the FY 2026–2028 rate period; b) solar sensor data from the University of Oregon Solar Radiation Monitoring Laboratory for the 72-month period from October 1, 2017, to September 30, 2023; and c) a variety of BPA archived data from the 72-month period from October 1, 2017, to September 30, 2023. The BPA archived data from the 72 month period needed for the forecast includes the total wind generation, the total wind forecast, the total solar generation, the total solar forecast, the total FCRPS generation, the total FCRPS schedule, the total non-federal thermal generation, the total non-federal thermal schedule, the BAA load, and the BAA load forecast for the period.

The following sections describe in detail how the forecast methodology data were obtained or developed. This dataset is used to estimate a netted imbalance signal for the BAA, representing the diversification of the combined load and generation error signals. It is this netted imbalance signal that is used in the percentile distribution calculations to identify the total balancing reserve capacity estimate.

2.2 Forecast of Generation Projects Online in the BPA BAA for the Rate Period

Developing the Balancing Reserve Capacity Quantity Forecast requires an estimate of the amount of generation that will be online within the BPA BAA during the rate period. This estimate includes both the actual generating projects that are online as of the time of the Study based on BPA records and a forecast of the projects that are either expected to enter or leave the BAA, decommission, or come online before the end of the FY 2026–2028 rate period. *See* Generation Inputs Study Documentation (Documentation), BP-26-FS-BPA-06A, Tables 2.1 and 2.2.

The forecast of projects that are expected to come online before or during the FY 2026–2028 rate period is based on a review of the pending requests in BPA's generator interconnection queue, information provided for the requests under BPA's Large Generator Interconnection Procedures (LGIP) and Small Generation Interconnection Procedures (SGIP), and the application of certain criteria. Forecasts of "future" projects throughout this Study are based on the assessment of the circumstances and information available at the time but are not intended to convey certainty about interconnection of a particular generating project.

To forecast which future generating projects will interconnect and the timing of such interconnections, BPA considered the status of interconnection requests in BPA's interconnection queue as of August 2024. The requested interconnection date in each interconnection request is only one of several factors considered to assess a potential interconnection date for a project. Prior to interconnecting, each future project must go through the interconnection study process, for which BPA completes a series of studies prior to offering an interconnection agreement and interconnection date. This can be an extended process, and the timing for completion can vary substantially; therefore, the evaluation of certain objective factors is necessary to make projections about the status of future projects. Some of the factors include:

- The status of the interconnection study process. Requests in the earlier stages of the study process are less likely to interconnect during the FY 2026-2028 rate period.
- The status of the environmental review process and interconnection customer permitting process for the request. As a federal agency, BPA must conduct a review under the National Environmental Policy Act (NEPA) and other federal laws before deciding whether to interconnect a particular generator. This review can take a substantial amount of time, and BPA typically coordinates its review to coincide with the customer's state or county environmental permitting process. Requests that are not far along in those processes are less likely to interconnect during the FY 2026-2028 rate period.
- Interconnection and network project additions that affect the time required to complete an interconnection. As studies progress, BPA and the customer develop a more definite plan of service, and the time to construct is better defined. The particular network additions and interconnection facilities required to interconnect the generator and the time it would take to construct those facilities are taken into account.
- Information received in direct discussions with each developer about its plans (*e.g.,* project scheduling, financing, federal and state incentives, turbine-ordering

commitment). A significant factor that affects the interconnection forecast is the date when a customer executes an engineering and procurement agreement, which allows BPA to incorporate the project in BPA's construction program schedule, begin work on the necessary interconnection facilities design, and begin ordering materials and equipment with a long procurement lead time.

- The execution of an interconnection agreement and commitment by the customer to fund all BPA facilities necessary for the interconnection. A construction program schedule is included in the agreement. Executing an interconnection agreement usually occurs just prior to the construction phase of a project.

Documentation Table 2.1 identifies the amount of installed capacity that the Study assumes will be online during the FY 2026-2028 rate period for each type of generation accounted for in the Balancing Reserve Capacity Quantity Forecast. Over the rate period, the forecast of installed wind capacity is an average of 3,395 megawatts (MW); installed solar capacity is an average of 1,450 MW; non-federal thermal capacity is an average of 1,583 MW; and non-AGC controlled FCRPS capacity is an average of 3,384 MW.

2.3 Forecasting Future Wind Generation Output Data

Forecasting the balancing requirements for the rate period requires estimating minute-by-minute generation output of all existing and future wind projects forecasted to be online in the BPA BAA for the FY 2026-2028 rate period. For generation data of existing wind projects, 72 months of one-minute actual average generation data from BPA's Plant Information (PI) system are used. The data covers generation from all existing wind generators in the BPA BAA for the period from October 1, 2017, to September 30, 2023. For existing wind projects, a combination of estimated minute-by-minute generation levels (prior to their online date) and one-minute actual average generation data from BPA's PI system (after their online date) are used. For wind projects online or forecast to come online after September 30, 2023, only estimated minute-by-minute generation levels are used. These estimates are discussed below in Sections 2.3.1 and 2.3.2.

BPA implements reliability tools—such as Operational Controls for Balancing Reserves (OCBR) and the Oversupply Management Protocol—that impact balancing reserve deployments for the BAA. These reliability tools can require a wind operator to decrease the output of its project below the optimized wind profile, so these times are identified in the data and replaced with estimated minute-by-minute generation. All generation data obtained from BPA's PI system are reviewed for missing data and any missing data points are filled in using estimated minute-by-minute generation, and contingency reserves are credited back to any wind generation that used those contingency reserves. All of this helps ensure that the filled-in data reflects the trends of BPA's PI system archived data.

2.3.1 Methodology for Determining Correlations and Lead or Lag Times

To help estimate minute-by-minute generation for future projects and to aid in data-scrubbing of existing generator data, the correlations and time delays between existing wind projects in BPA's BAA and the locations of future and existing wind projects are used. Documentation Table 2.2 includes the locations by county of the variable energy resource (VER) projects in the Balancing Reserve Capacity Quantity Forecast for the FY 2026-2028 rate period. A west-to-east wind pattern generally prevails in the locations of many future and existing wind projects in BPA's BAA, and generally the future wind project generation is predicted by using leading (earlier in time) generation values from an existing project that is west of the future project or lagging (later in time) values from an existing project that is east of the future project.

BPA determines the correlations and time delays in different ways depending on the data available for particular projects. For existing projects online prior to September 30, 2023, BPA derived correlations and time delays using actual minute-by-minute generation data from BPA's PI system. To derive correlations and time delays from the actual minute-by-minute data, a mathematical modeling tool, MATLAB ("matrix laboratory"), was used to calculate correlations between the minute-by-minute data for all existing wind projects at different time offsets. For each pair of existing wind projects, the time delay resulting in the highest correlation was used to define the correlation and time delay between those projects.

For projects that were not online prior to September 30, 2023, correlations and time delays were calculated using the numerical weather prediction model data provided by the National Renewable Energy Laboratory (NREL) and 3TIER, a wind forecasting company in Seattle, WA. This data predicts wind speed at standard gridded locations across the Pacific Northwest for calendar year (CY) 2004–2006 at 10-minute intervals. Using the forecast of wind generation online in the BPA BAA described in Section 2.2 and its associated geographic coordinates (latitude and longitude), 10-minute interval time series data were extracted for all existing and future wind projects. To derive correlations and time delays from the numerical weather prediction model data, MATLAB was used to calculate correlations between the 10-minute interval time series data for all existing and future wind projects at different time offsets. For each pair of existing and future wind projects, the time delay resulting in the highest correlation was used to define the correlation and time delay between those projects.

Documentation Table 2.2 identifies the existing and future VER projects that are forecast to be online during the rate period. The table is organized according to the month and year that the project went into service or is expected to be in service. Entries for existing projects include the installed capacity in megawatts and the month and year that the project reached its installed capacity. Entries for future projects include the proposed installed capacity and the completion date (month and year) on which the project is expected to reach its installed capacity.

2.3.2 Estimating Wind Project Generation

Once the correlations and lead or lag times for each pair of wind projects are determined, the output of existing wind generation and installed capacity of the existing and future wind projects is used in conjunction with the correlations and leads or lags to calculate the estimated minute-by-minute generation of all future wind projects through the end of the rate period and to fill in any missing data for the existing projects. The most strongly correlated plant is used in the methodology described below, unless it also had a missing data point during its corresponding time-delayed point. In that case, the second-most strongly correlated plant would be used, and so on down the line.

The estimated minute-by-minute wind project generation is forecast using the following assumptions. To model the estimated project's generation output, the existing project's generation output is scaled by multiplying by the estimated project's FY 2026-2028 forecast capacity in megawatts and dividing by the existing project's capacity. This calculation assumes a linear relationship between project capacity, wind flow, and generation output, and that a larger project with a greater capacity generates more energy from a particular amount of wind. Then, the total estimated project generation is determined by time-shifting the scaled generation of the existing project to the correct timeframe based on the calculated lead or lag time to the estimated project. This time shift helps express an estimated project's generation for a particular minute as a function of an existing project's generation.

The following example illustrates how the estimated project generation is calculated. In this example, a 150 MW wind project (Project A) has the strongest correlation with existing Project B (100 MW with a one-minute lag). Project A's estimated generation for any particular minute is determined using the following equation:

$$\textit{Project A} = (150/100) \times (\textit{Project B}^{-1minute})$$

These calculations are performed for all estimated wind generation through the end of the rate period. For the amount of installed wind assumed for each month of the rate period, the total wind generation is calculated by adding the minute-by-minute existing and estimated wind generation for that month. The resulting total wind generation is used to forecast the balancing reserve capacity requirements for the rate period.

2.4 Forecasting Future Solar Generation Output Data

Forecasting the balancing requirements for future solar generation during the rate period requires estimating future minute-by-minute generation output of all existing and future solar projects in the BPA BAA. For existing solar projects, up to 72 months (depending on the start date of the plant) of one-minute actual average generation data from BPA's PI system is used. The data covers generation from all existing solar generators in the BPA BAA for the period from October 1, 2017, to September 30, 2023. For solar projects that came online between October 1, 2017, and September 30, 2023, a combination of estimated minute-by-minute generation levels (prior to their online date) and one-minute actual average generation data from BPA's PI system (after their online date) are used. For solar projects online or forecast to come online after September 30, 2023, only estimated minute-by-minute generation levels are used. All generation data obtained from BPA's PI system are reviewed for missing data and any missing data points are filled in using the estimate minute-by-minute generation, and contingency reserves are credited back to any solar generation that used those contingency reserves. This helps ensure that the filled-in data reflect the trends of BPA's PI system archived data.

2.4.1 Historical Meteorological Sensor Data

To estimate the minute-by-minute solar generation levels for plants not yet online or to supplement plants that were not online for the entirety of the data set, historical meteorological sensor data is obtained and converted into a generation signal. This meteorological dataset is obtained from the University of Oregon Solar Radiation Monitoring Lab, whose network of sensors across the Pacific Northwest capture irradiance, temperature, and various other data at varying time scales.

For the solar generation estimate, we select sensor data sites with one-minute time resolution that measure both direct and diffuse irradiances and are as close as possible to the locations of each of the solar plants forecast to come online during the rate period. In this Study, the data from the following four sensor locations were used: Cheney, WA; Hermiston, OR; Burns, OR; and Silver Lake, OR.

2.4.2 Calculating Total Irradiance

For each of the four sensor datasets, direct and diffuse irradiance must be appropriately converted and combined to represent the total irradiance that would be seen by a solar panel in that location. To calculate this, we calculate various time-of-day and day-of-year parameters based on the position (latitude and longitude) of the sensor location. These parameters include:

- Solar Time—an adjustment to local standard time based on the longitudinal shift within the time zone;
- Declination Angle—the Earth tilt angle for that particular date;
- Solar Altitude Angle—the angle at which the sun is seen at the site relative to the horizontal plane for that particular minute;
- Solar Azimuth Angle—the angle between due south and the horizontal projection of the sun for that particular minute;
- Tracking Angle—the angle of tilt of the solar panel as it tracks the sun for that particular minute, assumed to have a north-south tracking axis orientation; and
- Angle of Incidence—the angle at which the sun's rays hit the panel for that particular minute.

For the Declination Angle parameter, a value is computed for each day of the year. For each of the other parameters listed above, a value is computed for each minute of each day of the year. In doing so, the parameters respect the seasonal and daily differences in the sun's position in the sky relative to the given sensor location. Using these calculated parameters, along with the measured direct and diffuse irradiances referenced in Section 2.4.1, we are then able to compute the total irradiance that would be seen by a solar panel at the sensor location. To view the equations associated with each of these calculations, see Documentation Tables 2.3 and 2.4.

2.4.3 Conversion of Irradiance to Power

With total irradiance computed, the output must be translated to electrical power output. To do so, a thermal model is calculated to adjust for variations in power output with respect to panel and ambient temperatures. The inputs to these calculations include a cell temperature coefficient, a static temperature coefficient, and measured ambient temperature. The cell temperature coefficient and measured ambient temperature are used to calculate the minute-by-minute cell temperature. A minute-by-minute temperature adjustment is then calculated using the cell temperature and the static temperature coefficient. This temperature adjustment, along with overall panel efficiency, the direct current (DC) nameplate, and the calculated total irradiance described in the previous section, are used to calculate the minute-by-minute estimated DC power output.

In the current Study, the following parameter settings are used:

- Cell temperature coefficient = 0.035 $^{o}C/(W/m^{2})$
- Static temperature coefficient = 0.4%/^{o}C
- Overall panel efficiency = 83%
- Inverter loading ratio = 1.5

Note that the inverter loading ratio represents the ratio of DC nameplate to alternating current (AC) nameplate. The DC nameplate is calculated to be the AC nameplate multiplied by the inverter loading ratio. This ratio represents the increasing trend in industry to oversize total panel DC capacity with respect to the amount of power the inverters at the site can convert to AC to increase the capacity factor of these plants. To view the equations associated with each of these calculations, see Documentation Table 2.5.

2.4.4 Scaling Point-Source Power to Estimated Solar Project Generation

DC power output must be scaled and converted to represent the AC power output for the given forecasted solar plant. Scaling the output to the proposed AC nameplate must capture the appropriate variability of the generation nameplate being estimated. In particular, variability should decrease as the size of a proposed plant increases, to reflect the decreasing impact of smaller weather events on an increasingly larger footprint. We employ a rolling average calculation to smooth the variability of the point source data used, with an increasing time interval to correspond with an increasing size of a proposed plant. *See* Documentation, BP-26-FS-BPA-06A, Table 2.6, line 2.

To determine the length of the rolling average interval, DC nameplate is used. The DC power output is then clipped to the AC nameplate. Any DC power produced above the AC nameplate will not be converted by the inverters, and thus any values above AC nameplate are simply set equal to the AC nameplate. Lastly, the estimated output is shifted forward or backward in time based on the longitude of the forecasted plant relative to the longitude of the sensor location, to account for the difference in time at which the plant will "see" the sun's position. To view the equations associated with each of these calculations, see Documentation Table 2.6.

2.5 Accounting for Other Non-AGC Controlled Generation

Estimating the balancing reserve capacity requirements during the rate period for all non-VER generation not controlled by AGC (Non-AGC Generation) requires analyzing historical minute-by-minute generation levels and corresponding schedules of the existing Non-AGC Generation in the BPA BAA and accounting for future use by all projects expected to be online during the rate period in the BPA BAA. For existing generation analysis, Non-AGC Generation is split into two subsets: non-controlled FCRPS generation and non-federal thermal generation. Thermal generation includes nuclear plants, coal-fired plants, natural gas plants, combined-cycle plants, boiler or steam-driven plants, and biomass plants. Non-federal hydroelectric generation is netted into the BAA load data, so the balancing reserve capacity requirements of such generation is included within the load balancing reserve capacity requirement as discussed in Section 2.6. Non-AGC FCRPS generation are assessed a separate balancing reserve capacity requirement, which is self-supplied by Power Services through the FCRPS.

2.5.1 Analyzing Historical Use by Existing Non-AGC Controlled Generation

For data on generation and schedules of existing Non-AGC Generation, 72 months of one-minute actual average generation and schedule data from BPA's PI system are used. The data covers generation and schedules from all existing Non-AGC Generation in the BPA BAA for the period from October 1, 2017, to September 30, 2023. The data is scrubbed for missing data periods, and contingency reserves are credited back to any Non-AGC Generation that used those contingency reserves. Actual data from Non-AGC Generation is included only after the generation comes online, as there is no reliable method to predict generation prior to commissioning of the plant.

2.5.2 Estimating Future Non-AGC Generation

Accounting for future Non-AGC Generation assumes that the historical usage trends continue in the rate period. To calculate the additional balancing reserve capacity requirements for future Non-AGC Generation, the balancing reserve capacity calculated in Section 2.8 for that type of generation (FCRPS or non-federal thermal) is divided by the existing installed capacity for that type of generation to create a reserves-per-installed capacity factor. The forecast installed capacity for the future project is then multiplied by the reserves-per-installed capacity factor to determine the balancing reserve capacity requirements needed to operate the future project. Currently, no new Non-AGC Generation is forecast to come online in the FY 2026-2028 rate period.

2.6 Load Estimates

The following sections describe derivation of the actual BAA loads and the BAA load forecasts that correspond to particular levels of installed generation used in the forecast. Non-federal hydroelectric generation is netted with the BAA loads and non-federal hydroelectric schedules are netted with the BAA load forecasts for the entirety of this Study.

2.6.1 Accounting for Pump Load

Load estimates start with BAA load posted on BPA's external operations website. BPA Balancing Authority Load and Total VER, Hydro, and Thermal Generation, Chart and Data, Rolling 7 Days, *available at* http://transmission.bpa.gov/Business/operations/Wind/default.aspx. The BAA load posted on the operations page reflects the total generation in the BPA BAA minus the total of all interchanges (transfers to and from adjacent BAAs). BPA's pump load is load associated with operating the pumps at Grand Coulee to fill Banks Lake for irrigation purposes, as determined by U.S. Bureau of Reclamation (Reclamation) requirements. Pump load is not part of the load forecast, because this load is scheduled at precise times, it is not affected by weather variation (it has the same power draw whether it is 30 degrees or 100 degrees F), and Grand Coulee generation serves this load directly. Thus, it does not affect the rest of the controlled hydro system or add any variation that requires the use of balancing reserve capacity. For these reasons, the pump load is subtracted from the BAA load prior to using BAA load numbers in the balancing reserve capacity requirements calculations.

2.6.2 Actual BAA Load Amounts that Correspond with Generation Installed Capacity Levels

To simulate BAA load that corresponds to the rate period (FY 2026-2028), 72 months of BAA load that corresponds to the forecasted FY 2026, FY 2027 and FY 2028 load levels must be created. The actual BAA load data for each fiscal year in the dataset (fiscal year range from October 2017 through September 2023) is scaled by the load growth rate (growth or decay) between the actual historical fiscal year load level seen and the forecasted fiscal year load level in the Study. The table below shows the load growth rates from FY 2018-2023 to FY 2026, FY 2027, and FY 2028. The load growth factors are based on forecasts for total BAA load from the BPA load forecasting group.

	FY 2026 Load	FY 2027 Load	FY 2028 Load
FY 2018 Load	1.1314	1.1602	1.1856
FY 2019 Load	1.1341	1.1630	1.1885
FY 2020 Load	1.1356	1.1645	1.1901
FY 2021 Load	1.0888	1.1165	1.1410
FY 2022 Load	1.0761	1.1034	1.1276
FY 2023 Load	1.0442	1.0708	1.0943

2.6.3 BAA Load Forecasts

To determine the BAA load forecasts, system load estimates from BPA's PI system are used. The same load growth multipliers shown above in Section 2.6.2 are applied to this base forecast to determine the forecasts for the future years. The load forecast assumption in the Study takes into account the calculation used by BPA's AGC system in the real-time calculation of balancing reserves deployed. The error of the load forecast from BPA's PI system for the current hour is calculated at 10 minutes before the top of the hour and applied forward to the two-hour out-load forecast as an adjusted load forecast. The inputs to the adjusted load forecast are the average load from 10 minutes into the hour to 50 minutes into the hour and the system of record load forecasts for the current hour and two hours out.

2.7 VER Scheduling Accuracy Assumptions

VER schedules for existing plants are assumed to use the BPA-provided hourly numerical weather power forecast (BPA VER Forecast). For future wind plants or any missing forecast data for existing wind plants, a 35/60 persistence is used as a proxy; this is calculated such that the 60-minute scheduling period uses a schedule equal to the one-minute average of the actual or estimated generation output of the project 35 minutes prior to the start of the scheduling period (average output for XX:24 to XX:25). All solar plant schedules are represented using the hourly average of a 35/15 persistence proxy. This is calculated such that the 60-minute scheduling period uses an average of the four 15-minute schedules across the hour equal to the one-minute average of the actual or estimated generation output of the project 35 minutes prior to the start of each 15-min scheduling period (average output for XX:24 to XX:25 for XX+1:00 to XX+1:15, average output for XX:39 to XX:40 for XX+1:15 to XX+1:30, etc.).

2.8 Calculation of Requirements for Total Balancing Reserve and Components

To calculate the capacity requirements for Total Balancing Reserves and the components of Regulating Reserves and Non-Regulating Reserves, BPA must first calculate an error signal for each. To calculate the total error signal, BPA subtracts total actual FCRPS generation, total actual non-federal thermal generation, total actual wind generation, and the total actual solar generation from the actual load to create a “Load net Generation” actual signal. BPA also creates a Load net Generation forecast signal by subtracting total FCRPS schedule, total non-federal thermal schedule, total wind schedule, and the total solar schedule from the load forecast. The total error signal used to calculate the Total Balancing Reserve Capacity is then calculated as the Load net Generation actual signal minus the Load net Generation forecast signal. The total error signal is then used in accordance with the Balancing Reserve Capacity business practice to calculate the total reserve requirement by calculating a 99.7 percent percentile distribution, setting the reserve requirements at 0.15 percent for total *dec* reserve and 99.85 percent for total *inc* reserve.

The delineation between Regulating and Non-Regulating reserves in the Total Balancing Reserve Capacity signal is based on the five-minute dispatch signals that the EIM market creates. To calculate the components of Regulating and Non-Regulating Reserves, each generation type and load must be analyzed in accordance with how the EIM would create their dispatch signals. For VERs, such as wind and solar, the market uses a persistence based forecast to feed the market optimization engine that originates from metered output of the VER generation at approximately 10 minutes prior to each five-minute interval. Similarly, the load forecast fed into the market optimization engine originates from metered BAA load on the same timeline as VERs. Thus, BPA chooses to use generation output from 10 minutes prior to each five-minute dispatch period to model the EIM market dispatch for VERs and to use metered BAA load from 10 minutes prior to each five-minute dispatch period to model the EIM market dispatch for load. For dispatchable resources, such as the non-federal thermal generation and the FCRPS generation, the market engine assumes the generation resource will follow their submitted base schedules from prior to the hour of operation. Thus, the EIM optimization engine produces dispatches that equal the schedules submitted by the resources and, in turn, BPA assumes the EIM market dispatches will equal the schedules in the historical data.

Once EIM dispatch signals are created for each generation type and load, the Regulating Reserve signal is created. A combined Load net Generation EIM dispatch is created by subtracting total FCRPS five-minute dispatch, total non-federal thermal five-minute dispatch, total wind five-minute dispatch, and the total solar five-minute dispatch from the load five-minute forecast. The Regulating Reserve signal is then calculated as the Load net Generation actual minus the Load net Generation EIM dispatch. In accordance with the Balancing Reserve Capacity business practice, a 99.7 percent percentile distribution is applied to the Regulating Reserve signal, resulting in 0.15 percent setting the *dec* Regulating Reserve requirement and 99.85 percent setting the *inc* Regulating Reserve requirement.

To avoid non-coincidental peaks, BPA calculates the Non-Regulating Reserve requirements as the difference between the total Balancing Reserves requirement and the Regulating Reserve requirement. For instance, *inc* Non-Regulating Reserve requirement is *inc* total Balancing Reserve requirement minus the *inc* Regulating Reserve requirement. To aid in the process of allocating among generation types as discussed in Section 2.9 below, BPA calculates the Non-Regulating Reserve signal as the Load net Generation EIM dispatch signal minus the Load net Generation forecast signal.

2.9 Allocating the Total Balancing Reserve Capacity Requirement Between Generation and Load

Once the forecast of the total balancing reserve capacity requirements is determined, the total is allocated between the various generation types and load, based on the relative contributions of each. The goal in determining this allocation is to find a statistically valid method under which the sum of the parts always equals the total (*e.g.,* FCRPS regulating *inc* reserves + non-federal thermal regulating *inc* reserves + solar regulating *inc* reserves +

wind regulating *inc* reserves + load regulating *inc* reserves = total regulating *inc* reserves). To do this allocation in a statistically accurate manner, incremental standard deviation (ISD) is employed to allocate reserves to load and generation types based upon how each contributes to the joint load-generation regulating reserve requirement and non-regulating reserve requirement.

The ISD measures how much load and generation contribute to the total load net generation balancing reserve capacity need based on how sensitive the total balancing reserve capacity need is with respect to the individual load and generation components. Stated differently, ISD shows how much the total balancing reserve capacity standard deviation changes given a 1 MW change in the load and/or generation standard deviation. ISD recognizes the diversification between the load and generation error signals; *i.e.,* the fact that the load and generation error signals do not always move in the same direction. The result of that diversification is a joint load-generation balancing reserve capacity requirement that is less than the sum of the individual requirements for load and generation.

To accurately capture the diversification between load and generation and still attribute appropriate shares of the balancing reserve capacity requirements to each generation type and to load, the error signals for all balancing reserve capacity components are sorted into 24 hourly bins based on time of day. For example, total regulating reserves, load regulating reserves, wind regulating reserves, solar regulating reserves, non-federal thermal regulating reserves, and FCRPS regulating reserves are all sorted among 24 bins: one bin for all data points falling in hour ending 1 (HE1), one bin for all data points falling in hour ending 2 (HE2), and so on. ISD is performed on each hourly bin to determine a balancing reserve capacity requirement for every component. An example of the ISD calculations is presented in Documentation Table 2.7. Then the maximum of the 24 hourly bin percentile distributions is found. Finally, the total reserve requirements calculated are disaggregated using the ratio of each component's maximum 24-hour requirement to the sum of all of the maximum 24-hour requirements. An example of these calculations for the load regulating *inc* reserve component is presented in Documentation Table 2.8.

2.10 Calculation of Balancing Reserve Capacity Quantity Forecast Restricted to the FCRPS Capability

The FCRPS has a maximum capability of 900 MW *inc* and -1100 MW *dec* on a planning basis (FCRPS Max), which is exceeded by the results of Section 2.8. *See* Documentation, BP-26-FS-BPA-06A, Table 2.9. The calculation below describes the derivation of values used to allocate balancing reserve capacity between the different classes when the Balancing Reserve Capacity Quantity Forecast exceeds the maximum capability of the FCRPS. These values are also used to set base VERBS rates. These results are based on the assumption that the FCRPS will supply the total regulating reserves for the rate period while prioritizing non-regulating reserves for load service. For the FCRPS Max forecast, total regulating reserves calculated in Section 2.8 are held for the entire rate period. When total balancing reserves calculated in Section 2.8 are greater than the FCRPS maximum capability for *inc* or *dec*, total FCRPS Max non-regulating reserves for *inc* or *dec* are the difference between the FCRPS maximum capability and total regulating reserves. Allocations of regulating reserves by various generation types and load are held the same as calculated in Section 2.9.

Once the total FCRPS Max non-regulating reserves is calculated for the entire rate period, the FCRPS Max non-regulating reserves for load are set equal to the non-regulating reserves for load calculated in Section 2.9. If the non-regulating reserves for load calculated in Section 2.9 are greater than the FCRPS Max non-regulating reserves, non-regulating reserves for load are set equal to the FCRPS Max. If there are FCRPS Max non-regulating reserves remaining after allocation to load, then those reserves are allocated based on the existing allocations calculated in Section 2.9 for wind and solar by using the ratio of each allocation to the sum of the allocations from the results of Section 2.9. For example, wind FCRPS Max non-regulating *inc* reserves is the remaining non-regulating *inc* reserves times the wind non-regulating inc reserves divided by the sum of non-regulating *inc* reserves for wind and solar. The FCRPS Max total balancing reserves for each generation type and load is calculated as the sum of FCRPS Max regulating reserves and FCRPS Max non-regulating reserves. These calculations are repeated separately for *inc* and *dec* and for every month of the rate period.

2.11 Results

The Study forecasts the balancing reserve capacity requirements as a total for the BPA BAA and for the two components of balancing reserve capacity: regulating reserves and non-regulating reserves. The Study also forecasts the total balancing reserve capacity for each balancing reserve user type (generation types and load), and each of the two components for each user type.

2.11.1 Balancing Reserve Capacity Quantity Forecast

Documentation Tables 2.9 through 2.14 include the results of the Balancing Reserve Capacity Quantity Forecast. All of these results are based on the assumption that VER generators schedule consistent with the BPA VER Forecast. Documentation Tables 2.9 through 2.14 include the *inc* and *dec* amounts for each component of the total balancing reserve capacity requirement and the component balancing reserve capacity requirement for load, wind, solar, FCRPS generation, and non-federal thermal generation, respectively.

These requirements cover the balancing reserve capacity requirements for 99.7 percent of the time as defined in the Balancing Reserve Capacity Business Practice.

2.11.2 Balancing Reserve Capacity Quantity Forecast Restricted To FCRPS Capability

Documentation Tables 2.15 through 2.20 include the results of the FCRPS Max Balancing Reserve Capacity Quantity Forecast. All of these results are based on the assumption that the FCRPS will supply the total regulating reserves for the rate period while prioritizing non-regulating reserves for load service. The FCRPS has a max capability of 900 MW *inc* and -1100 MW *dec* on a planning basis. Documentation Tables 2.15 through 2.20 include the *inc* and *dec* amounts for each component of the FCRPS Max total balancing reserve capacity requirement and the FCRPS Max balancing reserve capacity requirements for load, wind, solar, FCRPS generation, and non-federal thermal generation. These requirements cover the balancing reserve capacity requirements restricted to the constraints of the FCRPS Max.

3. OPERATING RESERVE CAPACITY FORECAST

3.1 Introduction

Operating Reserve is the type of reserve that BPA is required to offer to transmission customers pursuant to Schedules 5 and 6 of BPA's Tariff. A transmission customer must either purchase this service from BPA or make alternative comparable arrangements to meet its Operating Reserve obligation. Operating Reserve backs up resources in the BPA BAA. Operating Reserve costs allocated to BPA Transmission Services are recovered through transmission rates and passed to BPA Power Services as an interbusiness-line transfer. Power Rates Study, BP-26-FS-BPA-01, § 9.3. Rates for Operating Reserve are developed in Section 4.4 of this Study and are shown in the ACS-26 rate schedule, 2026 Transmission Rate Schedule and GRSPs, BP-26-A-01-AP02. Operating Reserve is referred to in other contexts as "Contingency Reserve," such as in the North American Electric Reliability Corporation (NERC) reliability standard BAL-002-WECC-3, but for purposes of this Study, BPA refers to such reserve as "Operating Reserve."

This section describes a) the applicable Operating Reserve reliability standards that apply to the BPA BAA; and b) BPA's methodology for forecasting the amount of Operating Reserve for the rate period.

3.2 Applicable Reliability Standards for Operating Reserve

The Tariff obligates BPA to offer Operating Reserve, which includes both Spinning reserve capacity and Non-Spinning or supplemental reserve capacity. The Tariff requires at least half of the Operating Reserve to be Spinning reserve. BPA determines the transmission customer's Spinning and Supplemental Operating Reserve requirement in accordance with applicable NERC, Western Electricity Coordinating Council (WECC), and Western Power Pool (WPP) standards.

The current NERC reliability standard, BAL-002-WECC-3, requires each BAA to maintain sufficient Operating Reserve equal to the greater of a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency or b) the sum of 3 percent of hourly integrated load (generation minus station service minus net actual interchange) and c) percent of hourly integrated generation (generation minus station service).

3.3 Calculating the Quantity of Operating Reserve

BPA's Operating Reserve obligation forecast under BAL-002-WECC-3 (3 percent net generation plus 3 percent net load) is determined in the following steps: 1) compute the total Operating Reserve obligation for the BPA BAA; 2) identify the total amount that customers self- and third-party supply; and 3) compute BPA's Operating Reserve obligation by subtracting the amount of self- and third-party supply from the total BPA BAA obligation.

3.3.1 Total Operating Reserve Obligation

The first step in forecasting the total Operating Reserve obligation is to forecast load and generation in the BPA BAA as follows:

- Forecast load in the BPA BAA is based on load forecast sourced from the Agency Load Forecast (ALF). The annual percentage load growth in the BAA is applied to historical BAA loads. Monthly shaping based on historical averages is applied to the forecast annual load to generate the forecast loads in the BP-26 rate period.

- Generation forecast in the BPA BAA consists of four resources: hydro, thermal, wind, and solar. For each of these resource types, the forecasted inputs are applied to regression models to generate the forecast generation.
    - Hydro generation in the BPA BAA is based on regressions using streamflow forecasts provided by Power Services by each month of the rate period. The hydro forecast input is a forecast of streamflow at The Dalles for 30-water-year conditions. The Dalles is a proxy for streamflow conditions on the FCRPS as streamflow conditions indicate hydro generation in a given year.
    - Thermal generation in the BPA BAA is based on regressions that estimate an expected amount, given hydro, wind and load levels. When high hydro and wind conditions exist, this reduces thermal generation. When load increases, thermal generation tends to increase. Where thermal plants leave the BPA BAA, thermal generation is adjusted by reductions based on historical capacity factors.
    - Wind generation in the BPA BAA is based on expected wind capacity factor for each month. The capacity factor is applied to the forecast installed capacity for each month. When wind plants leave the BPA BAA, wind generation is adjusted by reductions based on historical capacity factors. When wind plants enter the BPA BAA, wind generation is increased for the installed capacity and adjusted by historical capacity factor.
    - Solar generation in the BPA BAA is based on expected solar capacity for each month. The solar nameplate is adjusted for plant factor to estimate output for average solar generation by month. When new solar plants enter the BPA BAA, solar generation is increased for the installed capacity and adjusted by historical capacity factor.

Using these forecast methods for load and generation, the total BPA BAA net load equals a monthly average of 6,928 MW for FY 2026, 7,262 MW for FY 2027 and 7,588 MW for FY 2028. The total BPA BAA net generation equals a monthly average of 12,231 MW for FY 2026, 12,198 MW for FY 2027 and 12,633 MW for FY 2028. Documentation, BP-26-FS-BPA-06A, Table 3.1.

The total Operating Reserve Obligation forecast for the BPA BAA is determined by taking 3 percent of the total generation plus 3 percent of the total load, which yields 574.8 MW in FY 2026, 583.8 in FY 2027 and 606.6 MW in FY 2028 (BP-26 average of 588.4 MW). Documentation, BP-26-FS-BPA-06A, Table 3.2, line 15.

3.3.2 Self- or Third-Party Supplied Operating Reserve Obligation

The second step involves determining the Operating Reserve obligation provided by self- and third-party supply. This determination is based on customer elections to self-supply or to obtain third-party supply as of May 1, 2025, for the BP-26 rate period. The calculation for self- and third-party supply is made by taking five-minute data from BPA's PI system for the last two full fiscal years of the total Operating Reserve Obligation and BPA Operating Reserve obligation. The total Operating Reserve obligation minus the BPA Operating Reserve obligation equals the amount for self- and third-party supply. A distribution curve of the self- and third-party supply data returns an expected value by month. The total self-supply and third-party provision is forecast to average 82.6 MW in BP-26. Documentation, BP-26-FS-BPA-06A, Table 3.2, line 31.

3.3.3 BPA Operating Reserve Obligation

The third step is calculating the BPA Operating Reserve obligation. The BPA Operating Reserve Obligation equals the difference of the total Operating Reserve obligation and the amount provided by self- and third-party supply. This calculation results in a forecast BPA Operating Reserve obligation of 494.1 MW in FY 2026, 503.2 MW in FY 2027 and 526.0 MW in FY 2028 (507.8 MW average for BP-26). Documentation, BP-26-FS-BPA-06A, Table 3.2, line 47.

4. ANCILLARY AND CONTROL AREA SERVICES

4.1 Introduction

This section of the Study 1) describes the design and calculation of the rates for the Ancillary and Control Area Services through which BPA recovers the generation input costs, and 2) supports the Ancillary Services and Control Area Services rate schedule (ACS-26 Rate Schedule) in the 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02. The calculations for the Ancillary and Control Area Service rates are shown in the Transmission Rates Study and Documentation, BP-26-FS-BPA-08, in Table 8.4. Table 1 in the Documentation contains the forecast of generation inputs revenues. Documentation, BP-26-FS-BPA-06A, Table 1.

This Study does not discuss the rates for two Ancillary Services that do not rely on generation inputs: 1) Scheduling, System Control and Dispatch, and 2) Reactive Supply and Voltage Control from Generation Sources. BPA addresses those rates in the Transmission Rates Study, BP-26-FS-BPA-08.

4.2 Ancillary Services and Control Area Services

The ACS-26 Rate Schedule includes rates for six Ancillary Services and six Control Area Services. All rates in the ACS-26 Rate Schedule are subject to the Rate Adjustment Due to FERC Order under Federal Power Act Section 212. *See* 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, GRSP II.C.

4.2.1 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the BAAs affected by the transmission service. As a Transmission provider, BPA is required to provide, and transmission customers are required to purchase:

- Scheduling, System Control and Dispatch Service, and
- Reactive Supply and Voltage Control from Generation Sources Service.

As noted above, these Ancillary Services are discussed in the Transmission Rates Study and Documentation, BP-26-FS-BPA-08.

In addition, consistent with current NERC standards, BPA is required to offer to provide the following Ancillary Services to transmission customers serving load within the BPA BAA:

- Regulation and Frequency Response Service; and
- Energy Imbalance (EI) Service.

BPA is also required to offer, consistent with applicable NERC standards, the following Ancillary Services to transmission customers serving load or integrating generation within the BPA BAA:

- Operating Reserve – Spinning Service (Spinning Reserve Service); and
- Operating Reserve – Supplemental Service (Supplemental Reserve Service).

The transmission customer serving load or integrating generation in the BPA BAA is required to acquire the last four Ancillary Services listed above from BPA, from a third party, or by self-supply.

4.2.2 Control Area Services

Control Area Service rates apply to transactions in the BPA BAA for which the reliability obligations have not been met through Ancillary Services or some other arrangement. The six Control Area Services are:

- Regulation and Frequency Response (RFR) Service;

- Generation Imbalance (GI) Service;
- Operating Reserve – Spinning Reserve Service;
- Operating Reserve – Supplemental Reserve Service;
- Variable Energy Resource Balancing Service (VERBS); and
- Dispatchable Energy Resource Balancing Service (DERBS).

Entities with resources or loads in the BPA BAA must purchase Control Area Services from BPA to the extent those resources or loads do not otherwise satisfy the reliability obligations that their energy transactions impose on the BPA BAA.

4.3 Regulation and Frequency Response Service Rate

RFR service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining systemwide frequency at 60 cycles per second (60 hertz (Hz)). RFR service is accomplished by committing online generation whose output is raised (*inc*) or lowered (*dec*) (through the use of AGC equipment) as necessary to follow the within-hour changes in load. RFR is composed of two balancing reserve capacity components: regulating (moment-to-moment variability), and non-regulating (longer duration within-hour variability, including differences between the scheduled and average load). NERC reliability standards require BPA to maintain sufficient within-hour reserve to cover the requirements of all load in the BPA BAA. Pursuant to Schedule 3 of the Tariff, BPA must offer this service when the transmission service is used to serve load within the BPA BAA. The transmission customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its RFR obligation. Customers may be able to satisfy the RFR obligation by providing generation to BPA with AGC capabilities.

There is no functional or cost difference between RFR offered as a Ancillary Service or a Control Area Service. The difference is that the Control Area Service is offered to customers serving load in the BPA BAA other than through the BPA Tariff.

4.3.1 RFR Sales Forecast

BPA forecasts RFR sales from the point-of-delivery load forecast for transmission customers serving load in the BPA BAA. The load forecast for RFR is the average energy served for each month of the rate period. The forecast of annual average load for RFR in the BPA BAA for the FY 2026-2028 rate period is 7,239 aMW. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, line 27.

4.3.2 RFR Rate Calculation

The generation inputs cost for Power Services to provide RFR is $27.409 million, as shown in Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, line 29. All transmission customers serving load in the BPA BAA are charged for RFR service based on the customer's load in the BAA on an hour-by-hour basis. Dividing the generation inputs costs for regulation by the average load results in an rate of 0.43 mills per kilowatthour (kWh). *Id.*, line 30.

4.4 Operating Reserve Service Rates

All transmission customers with an Operating Reserve obligation must purchase or provide Operating Reserve. Pursuant to Schedules 5 and 6 of the Tariff, BPA must offer both Spinning and Non-Spinning (*e.g.*, Supplemental) Reserve in accordance with applicable NERC and NWPP standards. The transmission customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Operating Reserve obligation. Under BPA's Operating Reserve business practice, customers may elect to self-supply or acquire Operating Reserve service from a third party. For the FY 2026-2028 rate period, the customer's election to acquire Operating Reserve from a third party has to occur no later than May 1, 2025. Customers that elect to self-supply or third-party supply their Operating Reserve obligation but default on their obligation will pay a higher rate. *See* § 4.4.3. The Operating Reserve Requirement is based on NERC Reliability Standard BAL-002-WECC-3, and is the sum of 3 percent of load and 3 percent of the generation located in the BPA BAA used to serve the transmission customer's firm load. The Operating Reserve requirement is split equally between Spinning and Non-Spinning.

4.4.1 Spinning Reserve Service

Spinning Reserve is provided by unloaded generating capacity that is synchronized to the power system and ready to serve additional demand. These resources must be able to respond immediately to serve load in the event of a system contingency. Spinning Reserve service is provided by generating units that are online and loaded at less than maximum output.

There is no functional or cost difference between Spinning Reserve service offered as a Control Area Service or Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by generators in the BPA BAA that may not have a transmission service agreement with BPA, but have energy transactions that impose a spinning reserve obligation on the BPA BAA.

The Spinning Reserve Service rate includes two rate components. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, ACS-26, §§ II.E, III.C. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Spinning Reserve Requirement. *See* Section 3 above. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The energy is settled as Generation Imbalance through ACS IV.A.2, unless provided through the WPP, in which case the energy is settled at the market index provided for in the WPP Reserve Sharing Agreement.

4.4.2 Supplemental Reserve Service

Supplemental Reserve Service is generating capacity that is not synchronized to the system but is capable of serving demand within 10 minutes, or interruptible load that can be removed from the system within 10 minutes. These reserves must be capable of fully synchronizing to the system and ramping to meet load within 10 minutes of a contingency.

There is no functional or cost difference between Supplemental Reserve service offered as a Control Area Service or an Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by generators (in the BPA BAA) that may not have a transmission service agreement with BPA but have energy transactions that impose a supplemental reserve obligation on the BPA BAA.

The Supplemental Reserve Service rate includes two rate components. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, ACS-26, §§ II.F, III.D. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Supplemental Reserve Requirement. *See* Section 3 above. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The energy is settled as Generation Imbalance through ACS § IV.A.2, unless provided through the WPP, in which case the energy is settled at the market index provided for in the WPP Reserve Sharing Agreement.

4.4.3 Operating Reserve Rate Calculation

The cost allocation methodology and quantity forecast of Operating Reserve for the FY 2026-2028 period are described in Section 4 above. The annual revenue requirement for Operating Reserve-Spinning is $29.214 million. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, line 20. The Operating Reserve–Spinning rate of 13.14 mills per kWh is calculated by dividing the Operating Reserve–Spinning revenue requirement by the billing factor. *Id.,* line 22. The annual average billing factor forecast is 254 MW for the spinning requirement. *Id.,* line 20. Customers that self-supply or third-party supply Operating Reserve-Spinning but default on their self-supply or third-party supply obligations will pay a default rate of 15.11 mills/kWh. *Id*., line 23. The default rate is calculated by including a 15 percent adder to the normal rate.

The annual revenue requirement for Operating Reserve-Supplemental is $15.018 million. *Id.,* line 21. The Operating Reserve-Supplemental rate of 6.75 mills/kWh is calculated by dividing the Operating Reserve-Supplemental revenue requirement by the billing factor. *Id.,* line 24. The annual average billing factor forecast is 254 MW for the Supplemental requirement. *Id.,* line 21. Customers that self-supply or third-party supply Operating Reserve-Supplemental but default on their self-supply or third-party supply obligations will pay a default rate of 7.76 mills per kWh. *Id.,* line 25. The default rate is calculated by including a 15 percent adder to the normal rate.

4.5 Variable Energy Resource Balancing Service (VERBS)

BPA provides VERBS as a Control Area Service to wind and solar generators in the BPA BAA. This service is necessary to support the differences between actual generation from wind and solar generation and their generation estimate *(e.g.,* schedule). BPA is required to offer this service pursuant to Schedule 10 of the Tariff.

VERBS provides the capacity necessary to provide GI service pursuant to Schedule 9 of the Tariff, and Schedule 9E when BPA is operating in the EIM, as well as to provide regulation and frequency response for generation. These services are provided by raising or lowering the output of committed online generation (through the use of AGC equipment) as necessary to follow the moment-by-moment changes in wind and solar generation, including differences between the scheduled and average generation across the hour. The obligation to maintain the balance between resources (including wind and solar generation) and load lies with Transmission Services. The variable energy resource owner/operator must either purchase this service from Transmission Services or make alternative comparable arrangements to satisfy its VERBS obligation.

The VERBS rates in Section III.E.2.a and III.E.2.b of the ACS-26 Rate Schedule are capacity charges to be applied to the greater of the maximum one-hour generation or installed capacity of a wind or solar generating resource in the BPA BAA. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02. These rates recover the cost of balancing reserve capacity provided by the FCRPS. Like RFR, VERBS is composed of two balancing reserve capacity components: regulating (moment-to-moment variability) and non-regulating (longer-duration within-hour variability, including differences between the scheduled amount and average generation). The VERBS rates for wind and solar resources for each of these two balancing reserve capacity components are listed separately in the rate schedule to allow for formulation of rates for new technology pilot participants under Section III.G of the ACS-26 rate schedule. *See id.*

For additional balancing reserve capacity needed beyond planned FCRPS capacity, a formula charge will be used to recover any additional costs. The formula used to assign those costs is described in Section III.E.3 of the ACS-26 Rate Schedule. *Id.*

4.5.1 VERBS Rate Calculation for Wind Generators

The revenue requirement for balancing reserve capacity for VERBS-Wind supplied by the FCRPS is $17.63 million for regulating reserves and $8.148 million for non-regulating reserves, for a total of $25.778 million. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, lines 37-38. The base VERBS-Wind rate is determined by the total VERBS-Wind revenue requirement divided by the rate period average of installed wind capacity for BP-26 of 3,393 MW, resulting in a rate of $0.63/kW per month. *Id.*, line 39.

4.5.2 VERBS for Solar Resources Calculation

The revenue requirement for balancing reserve capacity for VERBS-Solar supplied by the FCRPS is $19.03 million for regulating reserves and $1.979 million for non-regulating reserves, for a total of $26.8 million. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, lines 43-44. The base VERBS-Solar rate is determined by the total VERBS-Solar revenue requirement divided by the rate period average of installed solar capacity for BP-26 of 1,509 MW, resulting in a rate of $1.15/kW per month. *Id.*, line 45.

4.5.3 Formula Balancing Capacity Charge

The Formula Balancing Capacity Charge will recover the costs of acquiring balancing reserve capacity beyond planned FRCPS capacity. It will be calculated on a monthly basis and will use the proportion of an individual customer's contribution to the overall VERBS charges to assign costs. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, ACS-26, § III.E.3.

4.5.4 Direct Assignment Charge

The Direct Assignment Charge will recover the cost of BPA purchases of capacity during the rate period to provide VERBS to a specific customer. Customers who require incremental balancing reserve capacity purchases that are necessary to provide VERBS will be billed for all costs incurred above $0.164/kW-day for any incremental balancing reserve capacity acquisitions, and the applicable VERBS rate. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, ACS-26, § III.E.4. The Direct Assignment Charge could trigger under three scenarios: 1) the customer elected to self-supply but is unable to continue self-supplying one or more components; 2) the customer has a projected generator interconnection date after FY 2028 but chooses to interconnect during the FY 2026-2028 rate period; or 3) the customer elected to dynamically transfer its resources out of the BPA BAA, but the resource remains in the BPA BAA after the date specified in the customer election.

4.6 Dispatchable Energy Resource Balancing Service (DERBS)

Pursuant to Schedule 10 of the Tariff, BPA must offer DERBS to all non-federal dispatchable energy thermal resources in the BPA BAA. This Control Area Service provides the capacity necessary to provide GI service pursuant to Schedule 9 of the Tariff, and Schedule 9E when BPA is operating in the EIM, as well as to provide regulation and frequency response for generation. The dispatchable energy thermal resource must either purchase this service from BPA or make alternative comparable arrangements to satisfy its DERBS obligation. This balancing service for thermal generators is comparable to VERBS for wind and solar generators.

The capacity provided for DERBS is used to increase or decrease committed online FCRPS generation (through the use of AGC equipment) as necessary to follow the moment-by-moment changes in thermal generation relative to the schedule, including ramps between hours.

The DERBS rate in Section III.F of the ACS-26 Rate Schedule includes charges to be applied to the thermal generator's calculated monthly use of balancing reserve capacity. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02. For any hours that an imbalance is determined to be subject to a Persistent Deviation Penalty Charge, the customer is subject to a different and larger charge. *See* Section 4.7.3 below.

4.6.1 Rate Calculation

Hourly rates are calculated for use of *inc* and *dec* balancing reserve capacity. The forecast *inc* reserve capacity requirement is 15 MW, and the forecast *dec* reserve requirement is 0 MW. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, lines 9-10. The forecast annual revenue requirement for Power Services to provide *inc* capacity for DERBS is $1.484 million and to provide *dec* capacity is $0.033 million, as shown in *id.*, lines 32-33.

A non-federal dispatchable energy thermal resource in the BPA BAA is charged for DERBS based on its hourly use of balancing reserve capacity in the BPA BAA, unless the non-federal dispatchable energy thermal resource is able to self-supply or acquire third-party supply of balancing reserve capacity.

The DERBS billing factor uses the Station Control Error, which is the difference between the generation estimate and actual generator output. The generation estimate is the sum of the e-tags for each hour for generators that have e-tags for their scheduled output or the submitted hourly generation estimate in Customer Data Exchange (CDE) for customer's who do not schedule the output of their resource. Ramp periods between hours during which the generation estimate changes from the previous hour are calculated from 10 minutes before the start of the hour to 10 minutes after the start of the hour. Deviations from the calculated ramp represent Station Control Error during the ramp. For the DERBS *inc* billing factor, the five-minute maximum *inc* value each hour is summed across all hours of the month. Likewise, the DERBS *dec* billing factor uses the five-minute maximum *dec* value each hour summed over the month. The *inc* billing factor is calculated from the hourly maximum use of *inc* balancing reserve capacity that exceeds 3 MW as measured on a five-minute average basis for station control error. The *dec* billing factor is calculated similarly. The *inc* and *dec* charge each month is calculated for each individual generating facility as the respective *inc* and *dec* rate multiplied by the billing factor computed for the month.

It is not anticipated that any dispatchable energy resources will self-supply or acquire third-party supply of balancing reserves during the rate period. The forecast use of DERBS is based on a historical database of five-minute Station Control Error for each resource for the period October 2018 through September 2024. The data was adjusted to omit individual generators that are no longer or not anticipated to be in the BPA BAA during the FY 2026-2028 rate period.

A 3-MW dead band was applied to each generator's hourly station control error, and then the remaining *inc* and *dec* station control error was totaled across all generators. The forecast annual use is estimated from October 2018 through September 2024 actual DERBS usage, with adjustments to recognize that a number of generators were offline for extended periods. Such extended periods of offline generation are not anticipated to occur regularly in the rate period. This forecast is 3,037 MW of hourly deviation annually for *inc*, and

1,979 MW of hourly deviation annually for *dec*. Transmission Rates Study and Documentation, BP-26-FS-BPA-08, Table 8.4, lines 32-33.

Based on the forecast use of *inc* and *dec* balancing reserve capacity, the DERBS hourly *inc* rate is 40.71 mills per kW for use of *inc* balancing reserve capacity that exceeds 3 MW, measured as the hourly maximum of five-minute average data. *Id.,* line 34. The DERBS hourly *dec* rate is similarly calculated and is 1.38 mills per kW for use of *dec* balancing reserve capacity that exceeds 3 MW, measured as the hourly maximum of five-minute average data. *Id.,* line 35.

4.6.2 Direct Assignment Charges

Direct Assignment Charges will recover the cost of BPA purchases of capacity during the rate period to provide DERBS to specific customers. Customers who require incremental balancing reserve capacity purchases that are necessary to provide DERBS will be billed for all costs incurred above $0.164/kW-day for any incremental balancing reserve capacity acquisitions, and the DERBS rate. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02, § III.F.4.

The Direct Assignment Charge is triggered when a DERBS customer: a) elects to self-supply but is unable to continue self-supplying DERBS; b) was operating in another BAA, fails to elect to take DERBS service during the FY 2026-2028 rate period, and dynamically transfers into the BPA BAA during the FY 2026-2028 rate period; c) has a projected generator interconnection date after FY 2028, but chooses to interconnect during the FY 2026-2028 rate period; or d) elected to dynamically transfer its resource out of BPA's BAA but remains in the BPA BAA after the date specified in the customer election.

4.7 Energy Imbalance and Generation Imbalance Service

All debits or credits that Transmission Services calculates for imbalance rates are passed on to the provider of the energy dispatched for a given hour. Because the net amount on average is typically small, BPA does not forecast any revenue or cost associated with these services. BPA will post the average cost of energy dispatched for imbalance services, which will be applied when energy is taken or provided. The rates for GI and EI services are energy charges, not capacity charges. BPA provides GI and EI services under Schedules 9 and 4 of the Tariff, respectively. When BPA is operating in the EIM, GI and EI services will be provided under Schedules 9E and 4E of the Tariff, respectively.

4.7.1 Energy Imbalance Service

EI Service is provided for transmission within and into the BPA BAA to serve load in the BAA. All transmission customers serving load in the BPA BAA are subject to charges for EI unless they are BPA power customers receiving a service that provides demand and shaping to cover load variations. As noted, BPA provides the EI service pursuant to Schedule 4 of the Tariff when BPA is not operating in the EIM.

EI is the deviation, or difference, between actual load and scheduled load. A deviation is positive when the actual load is greater than the scheduled load, and a negative deviation is the reverse. The EI rate in Section II.D of the ACS-26 Rate Schedule establishes three imbalance deviation bands. 2026 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-26-A-01-AP02. Band 1 applies to the portion of the deviation less than the greater of ± 1.5 percent of the schedule or ± 2 MW. If a deviation between a customer’s load and schedule stays within imbalance deviation Band 1, the customer may return the energy at a later time. The customer must arrange for and schedule the balancing transactions. BPA uses deviation accounts to sum the positive and negative deviations from schedule over Heavy Load Hours (HLH) and Light Load Hours (LLH) periods. At the end of the month, any balance remaining in the accounts must be settled at BPA's average incremental cost for HLH and LLH periods.

BPA's incremental cost will be based on an hourly average cost of energy deployed by BPA for imbalances. Energy deployed from federal resources will be priced at the posted energy index, and energy deployed from non-federal resources will be priced at their deployment costs.

Deviation Band 2 applies to the portion of the deviation greater than Band 1 but less than ± 7.5 percent of the schedule or ± 10 MW. For each hour the energy taken is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost. For each hour the energy taken is less than schedule, the credit is 90 percent of BPA's incremental cost.

Finally, Deviation Band 3 is for the portion of the deviation greater than Band 2. For each hour the energy taken is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day determined separately for HLH and LLH. For each hour the energy taken is less than schedule, the credit is 75 percent of BPA's lowest incremental cost for any hour that occurs during that day, determined separately for HLH and LLH.

For any day that the federal system is in a spill condition, no credit is given for negative deviations for any hour of that day. If the energy index is negative in any hour that the federal system is in a spill condition, no credit will be given for negative deviations within Band 1, and the charge will be the energy index for that hour for negative deviations within Bands 2 and 3. For any hours that an imbalance is determined to be subject to a Persistent

Deviation penalty charge, the customer is subject to a different and larger charge. *See* Section 4.7.3.

4.7.2 Generation Imbalance Service

GI Service provides or absorbs energy to meet the difference between scheduled *(e.g.,* generation estimate) and actual generation delivered in the BPA BAA. All generators in the BPA BAA are subject to charges for GI service if Transmission Services provides such service under an interconnection agreement or other arrangement. BPA provides this service under Schedule 9 of the Tariff when BPA is not operating in the EIM.

The GI service rate in Section III.B of the ACS-26 Rate Schedule establishes three imbalance deviation bands. 2026 Transmission Rate Schedules and GRSPs, BP-26-A-01-AP02. Band 1 applies to the portion of the deviation less than the greater of ± 1.5 percent of the schedule or ± 2 MW. If the difference between a generator's schedule and its delivery stays within Band 1, the customer may return energy at a later time. The customer will arrange for and schedule the balancing transactions. BPA uses deviation accounts to sum the positive and negative deviations over HLH and LLH periods. At the end of each month, any balance remaining in the accounts must be settled at BPA's average incremental cost for HLH and LLH periods.

BPA's incremental cost will be based on an hourly average cost of energy deployed by BPA for imbalances. Energy deployed from federal resources will be priced at the posted energy index, and energy deployed from non-federal resources will be priced at their deployment costs.

Deviation Band 2 applies to the portion of the deviation greater than Band 1 but less than the greater of ± 7.5 percent of the schedule or ± 10 MW. For each hour the generation energy delivered is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost. For each hour the generation energy delivered is greater than the energy scheduled, the credit is 90 percent of BPA's incremental cost.

Deviation Band 3 is for the portion of the deviation greater than Band 2. For each hour the generation energy delivered is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day, determined separately for HLH and LLH. For each hour the generation energy delivered is greater than the energy scheduled, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day, determined separately for HLH and LLH.

Deviation Band 3 will not apply to wind and solar resources and new generation resources undergoing testing before commercial operation for up to 90 days. Instead, all deviations greater than Band 1 will be charged at the Band 2 rate unless specifically exempted. BPA will exempt solar resources from Band 3 due to the expected difficulty in forecasting the output of solar generation during changing cloud cover within an hour.

No credit is given for generation energy delivered during a scheduling period that is greater than the sum of remaining schedules when the generator has schedules curtailed for that period.

For any day that the federal system is in a spill condition, no credit is given for negative deviations for any hour of that day. If the energy index is negative in any hour that the Federal system is in spill condition, no credit will be given for negative deviations within

Band 1, and the charge will be the energy index for that hour for negative deviations within Bands 2 and 3.

4.7.3 Persistent Deviation

Persistent Deviation refers to a difference between scheduled and actual generation, or between scheduled and actual load, that continues in the same direction longer than a certain period of time (*e.g.,* four hours) and greater than a certain megawatt amount (*e.g.,* 20 MW). Persistent Deviation applies to both load (EI) and DERBS.

Persistent Deviation will apply both outside the EIM and when BPA is operating in the EIM. When BPA is operating in the EIM, the Persistent Deviation rate will be based on the higher of the applicable Locational Marginal Price (LMP) at the nearest point of interconnection for DERBS customers, or the Load Aggregation Point (LAP) for EI customers, or 100 mills/kWh. Because EIM Participating Resources will not settle GI directly with BPA, different rates will apply to EIM Participating Resources to make Persistent Deviation charges equivalent to the charges for Non-Participating Resources.

4.7.4 Intentional Deviation

Intentional Deviation refers to a difference between a VER schedule and the BPA-provided schedule value. When a resource sets their schedule to the BPA-provided schedule value the Intentional Deviation Penalty does not apply. If a resource schedules to a value other than the BPA-provided schedule value, then the Intentional Deviation Penalty would apply if their imbalance is greater than what would have otherwise occurred had they used the BPA value. The Intentional Deviation rate is $100 MWh and applies both outside the EIM and when BPA is operating in the EIM.

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