BP-14 Final Rate Proposal

Transmission Rates Study

BP-14-FS-BPA-07

July 2013

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
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
FHFO	Funds Held for Others

FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid C	Mid Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act

NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
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
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability

RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION TO THE TRANSMISSION RATES STUDY

1.1 Purpose

This Transmission Rates Study (Study) describes the rate design process and the calculations used for developing the transmission rates for BPA's wholesale transmission products and services for fiscal years (FY) 2014 and 2015. The primary purpose of the Study is to demonstrate that the rates have been developed in a manner consistent with statutory directives and will recover the allocated transmission revenue requirement for the rate period. The Documentation for the Study (Documentation) is found in BP-14-FS-BPA-07A, and the Transmission, Ancillary and Control Area Service Rate Schedules are found in BP-14-FS-BPA-10. Table 11 in the Documentation summarizes the transmission rate levels.

The Study also discusses the development and calculation of rates for two ancillary services that are associated with transmission service: (1) Scheduling, System Control, and Dispatch (SCD) Service and (2) Reactive Supply and Voltage Control from Generation Sources Service (also known as Generation Supplied Reactive (GSR) Service). The Generation Inputs Study, BP-14-FS-BPA-05, discusses the development and calculation of rates for the other ancillary services and for control area services.

The Study is organized into seven sections. The first is this introduction, which includes a discussion of the statutory and contractual basis for the rate development and an overview of the rate design process and methodology. Section two describes the sales and revenue forecasts used to calculate the rates for network and intertie services.

Section three describes revenue credits and other adjustments that are applied to the revenue requirements. Section four describes the calculation of the rates for transmission service over the Network segment. Section five describes the calculation of the rates for intertie transmission services. Section six describes the calculation of the rates for SCD and GSR services. Section seven discusses other transmission products and services and the General Rate Schedule Provisions.

1.2 Overview of the Basis for Rate Development

1.2.1 Statutes

In accordance with section 4 of the Federal Columbia River Transmission System Act (Transmission System Act), BPA constructs, operates, and maintains the Federal Columbia River Transmission System (FCRTS) to (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide interregional transmission facilities; and (d) maintain the electrical stability and reliability of the system. 16 U.S.C. § 838b.

Section 7(a)(2) of the Northwest Power Act sets forth the overall guidelines to be used in establishing BPA's rates. Under section 7(a)(2), rates are effective upon a finding by the Federal Energy Regulatory Commission (Commission or FERC) that the rates:

- are sufficient to ensure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the BPA Administrator's other costs;
- are based upon the BPA Administrator's total system costs; and

- insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the FCRTS.

16 U.S.C. § 839e(a)(2).

Section 9 of the Transmission System Act provides that rates shall be established (1) to encourage the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles; (2) to recover the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable number of years; and (3) at levels that produce such additional revenues as may be required to pay the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. 16 U.S.C. § 838g. Section 10 of the Transmission System Act allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal uses of the system. 16 U.S.C. § 838h.

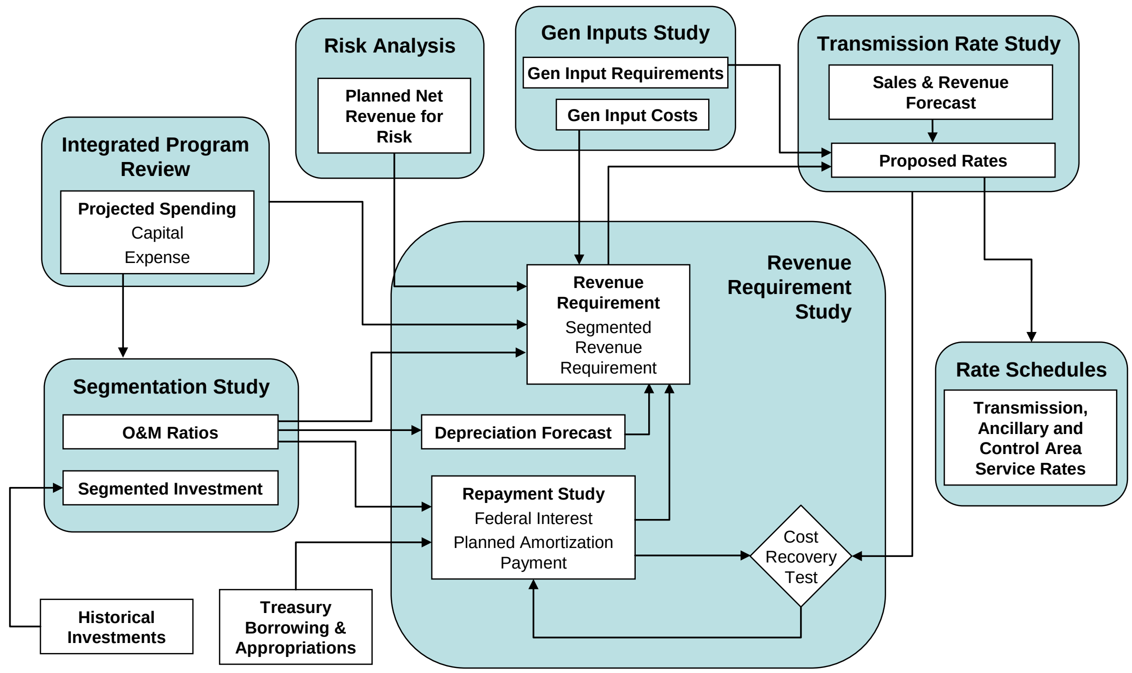
Section 212(i) of the Federal Power Act sets forth additional ratemaking requirements applicable to BPA for transmission rates in connection with transmission service ordered by the Commission. 16 U.S.C. § 824k(i). Section 211A of the Energy Policy Act of 2005 also authorizes the Commission to require unregulated transmitting utilities to provide transmission service at rates that are comparable to those that the unregulated transmitting utility charges itself. 16 U.S.C. § 824j-1.

1.2.2 Existing Contractual Arrangements

The transmission rates will apply to existing and new contracts established under BPA's Open Access Transmission Tariff (OATT), as well as legacy (grandfathered, pre-FERC Order 888) transmission service contracts, for the FY 2014–2015 rate period. For some contracts, such as Direct Service Industry (DSI) delivery contracts, rates change according to a contract schedule independent of the rate proceeding. Under those contracts, new rates will apply only if the rate is due to change under the contract schedule. Other contracts, such as Operations and Maintenance (O&M) and Use-of-Facilities (UFT) contracts, are fixed-price contracts and are not affected by the rate design process discussed in this study.

1.3 Overview of Transmission Rate Design Process and Methodology

BPA establishes transmission rates by determining the overall costs of the transmission system (revenue requirement) and allocating those costs among transmission customers. The following diagram illustrates BPA's transmission rate design process and shows the relationships between the various steps and inputs in that process.



The Study relies on the results of the Transmission Segmentation Study, BP-14-FS-BPA-06, and the Transmission Revenue Requirement Study, BP-14-FS-BPA-08, to calculate the rates. Sections 1.3.1 and 1.3.2 provide an overview of these studies.

1.3.1 Transmission Segmentation Study

The Transmission Segmentation Study, BP-14-FS-BPA-06, explains how BPA establishes its segments for the FY 2014–2015 rate period and determines the investment and O&M expenses for each segment. BPA has established seven segments for the purposes of developing rates for the rate period: Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Ancillary Services.

The segmented investment and segmented O&M costs identified in the Transmission Segmentation Study are an input to the Transmission Revenue Requirement Study, where they are used to determine the portion of the transmission revenue requirement that should be allocated to each segment.

1.3.2 Transmission Revenue Requirement Study

The Transmission Revenue Requirement Study, BP-14-FS-BPA-08, establishes the amount of revenues needed to ensure the recovery of the costs associated with providing wholesale transmission services for the rate period. The revenue requirement is based on program-level expenses and capital expenditures developed in the 2012 Capital Investment Review and Integrated Program Review (IPR) processes, which preceded the rate development process.

Transmission revenue requirements are set at levels sufficient to meet the annual operating expenses of the transmission system, to cover interest expense, and to recover minimum required net revenues to meet cash flow requirements and planned net revenues for risk, if any, to ensure that BPA meets its risk mitigation objectives. The Transmission Revenue Requirement Study includes a risk analysis to evaluate whether the rate proposal is sufficient to achieve a 95 percent probability of making end-of-year U.S. Treasury payments in full and on time during the two-year rate period. *See* Transmission Revenue Requirement Study, BP-14-FS-BPA-08, section 2.2, and Transmission Revenue Requirement Study Documentation, BP-14-FS-BPA-08A, Chapter 10.

The process used to develop the transmission revenue requirement consists of three parts. First, BPA prepares repayment studies for each year of the rate period, which include the outstanding and projected transmission repayment obligations for Congressional appropriations and bonds issued to the U.S. Treasury. Second, BPA evaluates projected annual operating expenses for the transmission system over the rate period. Third, BPA determines whether any minimum required net revenues or planned net revenues for risk are necessary. The sum of these figures is the overall revenue requirement for transmission. The Transmission Revenue Requirement Study and its Documentation describe these elements in detail.

The Transmission Revenue Requirement Study determines a segmented revenue requirement by allocating the overall transmission revenue requirement to the segments defined in the Transmission Segmentation Study, BP-14-FS-BPA-06. Chapter 2 of the Transmission Revenue Requirement Study Documentation, BP-14-FS-BPA-08A, describes this allocation. The segmented transmission revenue requirements for FY 2014–2015 are shown in Table 1 in the Transmission Rates Study Documentation, BP-14-FS-BPA-07A.

1.3.3 Transmission Rates Study

Development of the rates for the transmission and ancillary services addressed in the Study relies on two primary inputs: (1) sales and revenue forecasts developed as part of the Study; and (2) the segmented transmission revenue requirements developed in the Transmission Revenue Requirement Study. Section two of this Study discusses the sales and revenue forecasts used in calculating the rates, including adjustments to those forecasts made for rate development purposes. Section three describes revenue credits and other adjustments that are applied to the segmented revenue requirements before calculating the rates. Sections four through seven describe how the sales forecasts, segmented revenue requirements, and other inputs are used to calculate the rates for the transmission service and ancillary services in the Study.

2. SALES AND REVENUE FORECASTS

2.1 Overview

This Study forecasts sales for each of the various transmission services and certain ancillary services for purposes of developing the rates. Transmission sales forecasts are generally based on either forecast load or contract transmission demand, depending on the type of transmission service. The Study uses the sales forecast for two purposes: as the basis for the transmission revenue forecasts, which present the expected levels of revenue for the rate period from transmission and ancillary services rates and other sources; and in the calculation of rates, as described below.

BPA prepares two revenue forecasts, one forecasting the revenue at current (FY 2012–2013) rates and the other at proposed (FY 2014-2015) rates. These revenue forecasts are used in the Transmission Revenue Requirement Study to test whether current rates are sufficient to recover the transmission revenue requirement and whether proposed rates are sufficient to recover the transmission revenue requirement. See the Transmission Revenue Requirement Study, BP-14-FS-BPA-08, section 3.

Sales forecasts are discussed further in sections 2.2, 2.3, 2.4, and 2.5 below and are shown on Tables 4, 5, 9, 10, 13.1, and 13.2 in the Transmission Rates Study Documentation, BP-14-FS-BPA-07A. Revenue forecasts are discussed further in section 2.6, and the revenue forecasts at current and proposed rates are shown on Table 12 of the Documentation.

In addition, BPA also forecasts transmission credits and related interest expense associated with generator interconnection agreements and the California-Oregon Intertie (COI) upgrade project. These transmission credits are applied to customers' invoices for transmission service and result in non-cash revenue (the related interest expense represents noncash expenses). The non-cash revenues are included in the revenue forecasts because the transmission services to which they apply are included in the sales forecasts. BPA forecasts the transmission credits separately because the non-cash revenues and expenses have other impacts on revenue requirements and cost recovery. These impacts are described further in section 2.3.5 of the Transmission Revenue Requirement Study, BP-14-FS-BPA-08.

2.2 Sales Forecasts for Transmission Service on BPA's Network

Sales forecasts for long-term transmission services are generally based on the units of measure to which the charges for the service are applied. Sales forecasts of Network Integration (NT) transmission service are based on load forecasts, because the charges for this transmission service are based on the customers' loads. Sales forecasts of long-term Point-to-Point (PTP) transmission service, Integration of Resources (IR) transmission service, and Formula Power Transmission (FPT) service are based on transmission contract demand; that is, confirmed existing sales and expected future sales, because the charges for these services are based on amounts specified in the customers' transmission contracts.

Because short-term PTP service is not reserved far in advance, there are no contract demands on which to base the sales forecast. Instead, the forecast is developed using an analysis of the statistical relationship between historical short-term sales data and historical price spread and streamflow data. It is assumed that the historical relationship represents the future relationship between short-term sales and streamflow and forecast price spread. The methodology for forecasting sales for each transmission service is discussed in more detail below.

2.2.1 Sales Forecast for NT Transmission Service

Network Integration service provides transmission service for a customer's designated network load, including network load growth, over the Network segment. BPA forecasts sales for NT service using Point of Delivery (POD) load forecasts.

2.2.1.1 Development of POD Load Forecast for NT Service

BPA develops two monthly POD load forecasts for NT service: a non-coincident peak forecast and a coincident peak forecast. The non-coincident peak forecast, which is used to determine Network segment cost allocation, is a forecast of the customer's highest hourly load, which for each month is the sum of the hourly load at the customer's PODs on the hour in which this sum is the highest. The coincident peak forecast, which is used to calculate the NT rate and to develop the sales forecasts used to forecast revenue at the current and proposed NT rate, is a forecast of the customer's load at each POD on the hour of the monthly transmission system peak. These load forecasts include all residential, commercial, and industrial retail loads in the customer's service territory.

Determination of a Customer's Non-Coincident Peak Load Forecast

BPA uses a multi-step-process to determine the NT customers' non-coincident peak POD load forecasts.

Step 1: Regression Analysis of Historical Meter Readings

First, BPA uses a regression analysis to identify the historical relationship between historical POD load levels and temperature. A regression analysis evaluates how one variable (in this case load levels) changes, given changes in independent variables (such as temperature). The regression analysis identifies the statistical relationship between historical load levels at individual PODs and temperature, among other variables. For historical load level data, the analysis typically uses historical monthly meter readings from individual PODs from 1999 to 2011, a time period that includes a large enough sample to perform meaningful statistical analysis. A shorter time period is used for customers for which this time period would not accurately reflect load growth, such as a customer that added a sizeable new load in recent years.

For temperature data, BPA uses actual historical temperatures from National Oceanic and Atmospheric Administration weather stations from the same time period (for each POD, the analysis uses temperature data from a weather station near the POD). The analysis identifies the relationship between the load levels and temperature. The model confirms that load levels tend to increase when temperatures either increase or decrease. Increasing temperatures lead to greater use of air conditioning, while decreasing temperatures lead to use of heating equipment. In either case load increases.

The analysis also calculates the relationship between load levels and month of the year. The analysis confirms that in certain months loads are typically higher than in other months, regardless of temperature. For example, January loads are typically higher than March loads because there are fewer daylight hours and, thus, more lighting use in January than in March. As another example, December loads tend to be higher because of increased use of decorative lighting for the holiday season. The analysis determines the amount by which load changes in each month, regardless of temperature. The analysis assigns a variable to each month, referred to as the monthly indicator variable, to represent the amount by which load changes.

Finally, the analysis also calculates how historical load levels at each POD change independently from both temperature and month. The analysis indicates that individual PODs may have a load shape that is independent of those variables. For example, a particular POD may have new construction or technology changes that affect electrical consumption. As more households purchase large screen televisions, which use more electricity than smaller televisions, the load will increase. If new commercial buildings or homes are built and served through the POD, load at the POD will also increase. The analysis calculates the amount by which load changes over time, independent of temperature or month. The analysis assigns a variable to each month, referred to as the time trend variable, to represent the amount by which load changes over time independent of other variables.

BPA developed a forecasting model that incorporates the relationships identified by the regression analysis for each POD and applies indicators of future conditions, discussed below, to develop the load forecast. The model assumes that historical relationships between the dependent variable (load) at each POD and the independent variables (temperature, the monthly indicator, and the time trend variable) represent the future relationships, and therefore the historical relationships are projected into the future. The model applies variables representing possible future conditions to the relationships to produce a load forecast.

Step 2: Application of Indicators of Future Conditions to Model to Forecast Load at Each POD

Next, BPA forecasts the maximum hourly load at each POD in the customer's contract for each month of the billing period, using the relationships identified in the regression analysis. BPA inputs into the model independent variables that represent possible future conditions. The variables include a temperature indicator (average heating degree days and cooling degree days, calculated from average temperatures from 1970 to 2004), and the monthly indicator and time trend variables discussed above. Heating degree days are days that the daily average temperature (the average of the daily minimum and maximum outdoor temperatures on a given day) is below the area base temperature (temperature that reflects the use of heating and cooling equipment in that area and other characteristics of the residential, commercial, and industrial load) for the geographic area. Cooling degree days are days that the daily average temperature is above the area base temperature for the geographic area. There is a positive relationship between heating and cooling degree days and load change. More heating degree days mean colder than average temperatures and higher loads from increased use of heating equipment. More cooling degree days mean warmer than average temperatures and higher loads from increased use of air conditioning equipment.

The model next applies the monthly indicator variable and the time trend variable to forecast loads for each future month being evaluated. The monthly indicator variable triggers the model to include in the forecast the amount, estimated from historical loads, by which loads in that month have tended to change, regardless of temperature. For example, if the month being forecast is "January," the model forecasts loads based on the amount by which loads in January are historically higher than loads in other months, regardless of temperature. Similarly, the time trend variable triggers the model to include in the forecast the amount by which historical loads have changed over time, regardless of temperature and monthly indicator. For example, if the forecast is being developed for June in the first year of the rate period, the model will forecast loads differently, based on historical time trends from Step 1, than it would if the forecast was for June of the second year of the rate period. The time trend variable triggers the model to incorporate into the forecast the amount of load growth that is not attributable to temperature or calendar month.

After the inputs are included in the model, the model produces a forecast of the maximum hourly load at each POD for each month of the rate period.

Step 3: Adjustment of Maximum Hourly Load at the PODs

Because the maximum hourly load at each POD may not occur on the hour of the month in which the sum of the customer's load at all of its PODs is highest, BPA adjusts the forecast of the maximum hourly load at each POD by a coincident factor for each month. The coincident factor for each month for each POD is the average of the ratios of the historical POD load on the hour of the customer's monthly peak load to the historical POD load on the hour of that POD's peak load during the same month, for the same years used for the regression analysis (typically between 1999 and 2011). BPA multiplies the forecast of the maximum hourly load for the month at the POD by its coincident factor to determine the forecast POD load on the hour of the customer's peak load for the month.

Step 4: Determination of Customer's POD load forecast

BPA adds the adjusted POD load forecasts to determine the customer's highest hourly load for that month. The POD load forecast is used for the Network segment cost allocation.

Determination of A Customer's Coincident Peak POD Load Forecast

BPA forecasts coincident peak load on the hour of the monthly transmission system peak to calculate the BP-14 NT rate and to develop the sales forecasts to forecast revenue at the current and proposed NT rate. BPA develops the coincident peak forecast using the same methodology used for the non-coincident peak POD load forecast described above, with one exception. Instead of adjusting the individual POD forecasts by the coincident factor, BPA adjusts the maximum hourly load forecast for the POD to reflect the load on the hour of BPA's monthly transmission system peak. (The billing factor for the BP-14 NT rate is the customer's load on the hour of BPA's monthly transmission system peak.) These sales forecasts are shown in Documentation Table 4, lines 16-19, 39-42, and 53-56. The forecast of revenue at current rates is shown in Documentation Table 12.

2.2.1.2 NT Sales Forecast

As noted above, the Study develops a non-coincident peak NT load forecast for cost allocation and a coincident peak NT load forecast to calculate the NT rate for the NT sales forecast used in the revenue forecast. See Documentation Table 4 (forecasts developed in Steps 1-4 for FY 2014 and 2015 and the average over the rate period are shown in lines 21, 44, and 58; forecasts developed in Step 5 for FY 2014 and 2015 and the average over the rate period are shown in lines 17, 40, and 54).

For the Network segment cost allocation, BPA reduces the monthly non-coincident peak load forecasts to reflect the impact, in megawatts, of the NT Short Distance Discount

(SDD). To calculate the NT sales forecast and NT rate, BPA reduces the monthly coincident peak load forecasts to reflect the megawatt impact of the NT SDD. The SDD applies to a customer's Network Resources that are designated for at least 12 months and that use FCRTS facilities for less than 75 circuit miles for delivery to Network Load. BPA forecasts a reduction in sales due to the SDD by multiplying the average generation of the designated network resource during heavy load hours (HLH) by the SDD formula of 40% × (75 – distance) / 75. See Documentation Table 4 (forecasts developed in Steps 1-4 for FY 2014 and 2015 and the average over the rate period, including the SDD, are shown in lines 22, 45, and 49; forecasts developed in Step 5 for FY 2014 and 2015 and the average over the rate period, including the SDD, are shown in lines 18, 41, and 55).

For Network segment cost allocation, the Study calculates the average of the monthly non-coincident peak load forecasts, including the reduction for SDD, both over the rate period and for each fiscal year (12 NCP), discussed below in section 4. For the NT sales forecast and the NT rate, which establish the forecast of revenues at proposed rates from NT service for each fiscal year, the Study uses the average of the monthly coincident peak load forecasts for each fiscal year.

The Study uses the average NT non-coincident peak load forecast for each fiscal year without the reduction for SDD to calculate an average for the rate period, which is used to establish the cost allocation for SCD and GSR Ancillary Services (described further in section 2.4). Documentation Table 4, lines 21, 44, and 58. The Study uses the average

NT coincident peak load forecast for each fiscal year without the reduction for SDD to calculate an average for the rate period to establish the NT SCD and GSR Ancillary Services rates (described further in section 2.4).

2.2.2 Sales Forecast for PTP Transmission Service on the Network

Point-to-Point transmission service provides for the transmission of energy on a firm or non-firm basis from specific point(s) of receipt to specific point(s) of delivery under Part II of BPA's OATT. PTP service may be long-term (greater than one year in term) or short-term (hourly, daily, weekly, or monthly service). BPA separately forecasts sales of long-term and short-term PTP transmission service on the Network.

2.2.2.1 Long-Term PTP Transmission Service Sales Forecast

The Study includes forecasts of both confirmed (or existing) sales and expected additional sales of long-term PTP service on the Network during the rate period. The forecast of existing long-term PTP sales is based on:

(a) current long-term contract demands effective through the FY 2014–2015 rate period. This forecast includes all confirmed reservations for service during the rate period, including confirmed reservations for Conditional Firm Service.

(b) confirmed OATT section 17.7 customer deferrals (extensions of commencement of service), which reduce the sales forecast for the period of the deferral.

The forecast of expected additional long-term PTP sales on the Network is based on:

(a) long-term sales that have not yet been requested but are expected to occur during the rate period, including renewals of service under OATT section 2.2 (associated with existing agreements).

(b) Network Open Season reservations that are expected to be confirmed during the rate period (that is, service BPA expects to offer as a result of new or additional infrastructure BPA plans to place into service during the rate period).

(c) expected sales of Conditional Firm Service.

(d) long-term PTP sales to customers whose existing IR or FPT agreements are expiring during the rate period and that are expected to convert their transmission to PTP service on the Network.

(e) expected OATT section 17.7 customer deferrals (extensions of commencement of service), which reduce the sales forecast for the period of the deferral.

In forecasting expected additional long-term PTP sales on the network, BPA also considers of a variety of other sources of information. BPA examines requests in the queue that are seeking service. BPA consults with customers, account executives, and others with knowledge about expected long-term PTP requests that could be offered service. BPA receives information on expected service demand, the start date, the length of the service, and whether the customer will accept the offer. The forecast reflects the most likely scenario based on this information. If there is a great deal of uncertainty in the information gathered through this process, BPA looks at historical sales to the customer to determine whether the additional sales should be included in the forecast.

Table 4 in the Documentation includes the forecasts of confirmed PTP sales and expected additional sales for each month of the rate period. Table 4 also shows the total forecast of long-term PTP sales (the sum of confirmed sales and expected additional sales), the fiscal year averages, and the averages for the entire rate period.

Table 4 also includes adjusted forecasts that are developed in the Study to reflect the impact of the SDD in the PTP rate schedules. The SDD applies to the contract demand for any reservation using less than 75 circuit miles of BPA transmission. The adjusted forecasts reflect a reduction in sales due to the SDD by multiplying the contract demand for each reservation or request to which the SDD applies by the distance-based percentage: 40% × (75 – distance) / 75. This adjustment is made to both confirmed and expected sales to which the SDD applies.

The Study calculates both the average of the monthly sales forecasts, including the reduction for SDD, over the rate period and for each fiscal year. The average of the monthly sales forecasts, including the reduction for the SDD, for each fiscal year is used to establish the revenue forecast from long-term PTP sales. The average of the sales forecasts over the rate period, adjusted for the SDD, is used in the calculation of the Network unit cost, discussed below in section 4.

The Study uses the average PTP sales forecast for each fiscal year without the reduction for SDD to calculate an average for the rate period, which is used to establish the sales forecast for SCD and GSR services (described further in section 2.4). *See* Documentation Table 4.

2.2.2.2 Short-Term PTP Network Sales Forecast

Short-term PTP sales are firm or non-firm sales of less than one year, including monthly, weekly, daily, and hourly sales. Because short-term PTP service is not reserved far in advance, there are no existing contract demands on which to base the sales forecast. Therefore, the forecast of short-term PTP sales expected to occur during the rate period is based on historical short-term sales data and key market indicators—streamflow and market price spread—and seasonality (the calendar month of the short-term sale). Streamflow on the Columbia River and market price spread (the differences between prices in the Pacific Northwest and California) are key market indicators, because as they increase, short-term sales tend to increase. The analysis also accounts for seasonality, because sales tend to be higher in certain months, even holding the market indicators constant.

BPA develops the forecast of short-term PTP sales in three steps. First, a regression analysis (an analysis to evaluate how one variable changes, given changes in other independent variables) of historical data is performed to identify the relationships between sales and the market indicators and seasonality (that is, how sales change given changes in streamflow, price spread, and seasonality). The relationships are not one-to-one correlations. However, for purposes of this Study, the relationships are referred to as "correlations," because as streamflow and market price spreads increase, sales generally tend to increase. Second, BPA identifies the sets of data (streamflow, future market price spread, and seasonality) to be used as inputs to the short-term sales forecasting model (which is based on the correlations identified in the first step). Third, BPA develops the forecast of short-term sales. This method develops a forecast that reflects (1) historical relationships between sales and market indicators and (2) expected market conditions over the rate period.

Step 1: Regression Analysis of Historical Data to Identify Correlations

First, BPA performs a regression analysis, using Microsoft® Office Excel Professional Edition 2003, to determine the statistical relationship between historical short-term PTP sales and three historical market indicators—regulated streamflows in the Columbia River at The Dalles, the price spread (the difference between power prices) between two trading hubs in Northern California and the Pacific Northwest, and the calendar month of the data being evaluated. The analysis uses actual data from October 2007 through May 2012 for all three independent sets of data—sales, streamflow, and price spread (the calendar month is not a separate data set, but is based on these three variables). BPA uses historical regulated streamflow at The Dalles, obtained from the U.S. Geological Survey (USGS), because it is an indicator of the amount of power that will be generated and sold using short-term PTP service. In general, higher historical streamflow has a positive correlation with sales of short-term PTP service.

BPA calculates the price spread using power prices at North-of-Path 15 (NP-15, a trading point in Northern California) and at Mid-Columbia (Mid-C, a trading point in the Pacific Northwest) obtained from Intercontinental Exchange (ICE, an operator of over-the-counter electricity markets). The Mid-C prices are subtracted from the NP-15 prices. This is referred to as the NP-15 minus Mid-C price spread. The price spread provides a representation of the difference in power prices between Northern California (represented by the NP-15 prices) and the Pacific Northwest (represented by the Mid-C prices). In general, a price spread provides incentive for customers in the location with lower prices to sell power (and purchase short-term transmission with which to deliver it) to the location with higher prices. Thus, price spread is a driver of short-term transmission sales. For example, a positive price spread indicates that prices in Northern California are higher than those in the Pacific Northwest, and provides incentive for customers in the Pacific Northwest to sell power, and purchase short-term transmission with which to deliver it, to California.

Finally, BPA also uses the month of the sale because even if streamflow and price spreads remain constant from month to month, sales in certain months are higher than sales in other months. In general, sales in March through June are higher than sales in other months, and sales in September are lower than sales in all other months. This variable is referred to as "seasonality."

For sales of short-term PTP service to BPA's Power Services, the regression analysis is performed on historical short-term PTP sales against streamflow only because as streamflow increases, short-term sales to Power Services tend to increase, but price spread and seasonality do not tend to influence short-term sales to Power Services. This is because Power Services is obligated to dispose of the power generated on the Federal Columbia River Power System (FCRPS), regardless of the price.

For short-term PTP sales to all other transmission customers, BPA performs the regression analysis on historical short-term PTP sales against streamflow, price spread, and seasonality. For these customers, there is a statistically significant correlation between sales and streamflow, price spread, and seasonality. These customers are more likely to sell power (and purchase short-term transmission to do so) when streamflow conditions are high, but also when pricing conditions provide incentives to market power, and in certain months (particularly March through June). They are less likely to sell power and purchase short-term transmission when the price spread is too low to allow them to produce a profit and recover the cost of the additional transmission purchases, when streamflow at The Dalles is low, or in fall and winter months.

BPA developed a forecasting model that incorporates the correlations identified by the regression analyses and applies other inputs to those correlations, as discussed below, to develop the short-term sales forecast. The model assumes that historical correlations between sales on the one hand and streamflow, price spread, and seasonality on the other hand represent future correlations (with certain adjustments for risk). Certain streamflow and price spread data are input to the model as predictions of future conditions, and with those inputs and certain adjustments for variability, discussed in Step 3, the historical correlation is projected into the future to produce a sales forecast.

Step 2: Data to be used as Inputs to the Short-Term Sales Forecasting Model

As the second step in developing the forecast, streamflow, price spread, and seasonality data are identified to be used as inputs to forecast short-term sales. These inputs represent future market conditions in the model. The way the model uses these inputs is described further in Step 3 below. As the input for streamflow conditions, the model uses average streamflow at The Dalles from 1960 through 2010. This data set has streamflow data for each month in each of those years. This data set is a large enough sample size to account for short-term variations in the data and provides a reasonable potential range of streamflow scenarios in the rate period.

As the input for price spread conditions, Settlement Prices for Mid-C and NP-15 from ICE (the operator of over-the-counter electricity markets) are used to represent expected power prices during the rate period. ICE Settlement Prices are forward prices at which power can be purchased today to be delivered in a future month and which reflect the current market value of future power. The Mid-C Settlement Price is subtracted from the NP-15 Settlement Price to obtain the price spread to input to the forecasting model to predict future sales. This method is consistent with the use of the historical NP-15 minus Mid-C price spread to identify the correlation between short-term sales and price spread.

To account for seasonality, the model applies a multiplier to reflect the monthly trends observed in Step 1. The multiplier is based on historical sales in that month, regardless of streamflow or price spread. Because sales are generally highest in March through June, the multiplier is higher in those months than in the rest of the year.

These streamflow, price spread, and seasonality data are used as inputs to the historical correlations to produce a short-term sales forecast, as described below. Streamflow is used as the input for forecasting short-term sales to Power Services, and streamflow, price spread, and seasonality are used as the inputs for forecasting short-term sales to all other customers. This method is consistent with how the historical correlations are identified, discussed in Step 1.

Step 3: Development of the Forecast of Short-Term PTP Sales

BPA assumes that historical correlations between sales on the one hand and streamflow and price spread on the other hand will be the same as future correlations. To forecast short-term sales to Power Services, historical streamflow is input to the model as a prediction of future conditions, and the historical correlation is projected into the future to produce a sales forecast. To forecast short-term sales to all other customers, historical streamflow and forecast price spread are input to the model as predictions of future conditions, and again the historical correlation is projected into the future to produce a sales forecast. In both cases, the sales forecasts are modeled to include variability, as discussed below. Short-term sales are variable because they do not require long-term commitments and instead are purchased on an hourly, daily, weekly, or monthly (less than 12 months) basis. Short-term sales forecasts are also subject to uncertainty due to variability in streamflow and price spread.

To account for the impact of variability in short-term sales, BPA incorporates uncertainty around the streamflow, price spread, and other parameters using a Microsoft Excel add-in, @RISK, Professional version 5.05 (©Palisade Corporation). @RISK uses a Monte Carlo-based simulation (a method that uses repeated simulations, called games, to determine a range of possible outcomes) to run 5,000 short-term sales forecasting games and generate the distribution of the outcomes of those games around a mean. In running these games, three sources of uncertainty are modeled, all of which affect the short-term sales forecast: (1) variability in the correlations (that is, the risk of imperfections in the correlations); (2) variability of input data (streamflow and price spread); and (3) the possibility of limitations on available flowgate capability (AFC) or available transfer capability (ATC). The final short-term sales forecast is the average of the outcomes (sales forecasts) of all the games.

The variability in the correlations is the risk that the correlations between short-term sales and the market indicators are imperfect. This variability is also known as regression prediction error, because it represents possible error in the regression analysis. It is modeled to reflect the fact that the correlations do not accurately predict sales 100 percent of the time. The impact of this variability on the forecast of short-term sales to BPA Power Services is modeled separately from the modeling for other customers, consistent with the analysis outlined above.

To estimate the variability around the correlation between short-term sales to Power Services and streamflow, first the model is applied to predict what the short-term sales forecast for Power Services would have been for October 2007 through May 2012, based on streamflow data at The Dalles for that time period. The model's prediction is then compared to actual short-term sales to Power Services for that time period. The difference between predicted sales and actual sales indicates the possible magnitude of variability between the sales forecast produced by the model and actual short-term sales.

To determine the variability, the standard deviation is input into the model as an indicator of the range of possible error in the correlation between short-term sales to BPA Power Services and streamflow. This allows the model to generate a range of possible outcomes to account for possible error in the correlation.

For all customers other than Power Services, the impact of regression prediction error is analyzed in the same manner as described above, with one difference: both streamflow and historical price spread are inputs to the model to produce predicted sales for calculating differences between predicted and actual sales, and both streamflow and price spread are used in generating a range of possible outcomes to account for possible error in the correlation.

BPA also models the impact of variation in the forecast market indicators that are used to develop the sales forecast. BPA models variability in streamflow using the 1960–2010 streamflow dataset for the Columbia River at The Dalles. For each Monte Carlo game and for each year of the rate period, @Risk randomly chooses one year of streamflow data from the overall set of data and uses the data from each month of that year to simulate the streamflows in each month of the simulated rate period year.

BPA models variability in the price spread used in @Risk by using ICE Settlement Prices for Mid-C and NP-15 to represent expected power prices during the rate period. To model variability in prices, the model creates variability around the Settlement Prices by inputting factors that affect power prices, such as natural gas prices, Columbia River streamflows, and ambient temperatures in the BPA load area. By running games that randomly sample natural gas, streamflow, and temperature data and applying that data to the historical relationships between these factors and power prices, the model produces power prices at Mid-C and NP-15 for each month that are adjusted for natural gas price, streamflow, and seasonal variation. These power prices are then used to create the NP-15 minus Mid-C price spread that is used as the price spread input to the model.

BPA does not separately model variability in the seasonality monthly multipliers, because the variability modeled for streamflow and for price spread already takes monthly variability into account.

BPA also models the possibility of AFC or ATC being limited or not available during each month of the rate period. AFC or ATC may be limited when power flows on the system approach system limits. The availability of AFC or ATC could directly impact short-term sales—if AFC or ATC is limited or not available, BPA may impose a sales limitation, meaning that BPA may not be able to fully meet the anticipated demand for short-term sales. To model the possibility of AFC or ATC being limited or not available, BPA considers the percentage of time that the power flows on a transmission path are within 10 percent of the path's Operational Transfer Capacity (OTC) limit, which is the amount of power that can be reliably transmitted through a transmission path given current or forecast system conditions. OTC limits vary depending on path and system conditions (such as outages and seasonal path ratings). Power flows within 10 percent of the OTC limit indicate high use of the path. It is in these periods of high use that there is a possibility of a sales limitation being imposed.

To model possible sales limitations, BPA uses Supervisory Control and Data Acquisitions (SCADA) data for monitored Network flowgates from January 2008–February 2011. SCADA is a computer system that monitors, controls, and collects data regarding the transmission system. Monitored Network flowgates are the transmission paths on which BPA monitors and measures power flows and OTC in order to calculate ATC. The SCADA data show power flows and limits at each flowgate measured in five-minute increments. For each flowgate the percentage of time in each month that flows were within 10 percent of the path's OTC limit is calculated. The data is grouped by calendar month (that is, the data for each January from 2008 to 2011 is grouped, data for each February, and so on). For each calendar month group BPA then identifies the month within the group with the largest percentage of time that any flowgate is within 10 percent of its OTC limit. For example, January 2011 was identified as the January with the largest percentage of time that any flowgate was within 10 percent of its OTC limit (in this case, 8.7 percent of the time). BPA assumed that this percentage represented the percentage of the time that a limitation on sales would be imposed each year during that month. Thus, in this example, BPA assumed that a sales limitation would be imposed 8.7 percent of the time each January.

If a sales limitation is required, it indicates that AFC or ATC constraints may prevent BPA from selling short-term transmission service to meet full demand. Sales limitations can vary depending on system conditions. If a game being run by the model indicates that a sales limitation would be imposed, the model randomly chooses the portion of forecast short-term sales demand that can be granted given the available AFC or ATC, identified as a percentage (0% - 100%) of the full amount of short-term sales forecasted by the model. This percentage is applied to the full amount of short-term sales forecast by the model for that game. The result is a short-term sales forecast for that game that has been adjusted for possible AFC or ATC limitations.

As noted above, the market indicators and sources of variability are input into the @RISK model, which uses a Monte Carlo-based simulation to generate 5,000 games and generate a distribution of the outcomes of the games around a mean. The outcome of each game is a forecast for short-term sales for each month of each year of the rate period, given the assumed market conditions and variability. The resulting forecast of short-term sales for each month of the rate period is the mean, or average, of the 5,000 games. The model produces three forecasts: total short-term PTP sales to Power Services per month of the year, total hourly PTP sales to customers other than Power services per month of the year, and total short-term PTP sales (other than hourly) to customers other than Power Services per month of the year.

Short-term PTP sales may be for monthly, weekly, daily, or hourly service. Hourly firm and hourly non-firm service are charged the same hourly rate. Daily, weekly, and monthly firm and non-firm service are also all charged identical rates based on the number of days of the reservation—the Block 1 rate is charged for the first five days of a reservation, and the lower Block 2 rate is charged for day six and beyond.

As also noted above, the model produces forecasts of total short-term PTP sales to Power Services for each month of the year, total hourly PTP sales to customers other than Power services per month of the year, and total short-term PTP sales (other than hourly) to customers other than Power Services for each month of the year. BPA then allocates total short-term sales to Power Services across the different short-term products (hourly, Block 1, and Block 2). This allocation is based on the historical distribution of short-term sales across the three rates, using historical data from October 2007 through May 2012 (the same data used to forecast total short-term sales). The historical distribution of sales under each rate is applied to the total short-term sales forecast, resulting in a forecast for sales under each short-term PTP rate for each month of the rate period.

For customers other than Power Services, only products other than hourly must be allocated, since hourly sales are forecast independently. This allocation is based on the historical distribution of short-term sales between Block 1 and Block 2 for customers other than Power Services. The historical allocation of sales under each rate is applied to the total short-term sales forecast, resulting in a forecast for sales under the Block 1 and Block 2 rates for each month of the rate period. The forecasts for sales, by rate, to Power Services and to all other customers are then summed to determine overall short-term PTP sales forecasts for each month under each rate. The forecast of short-term PTP sales is shown in Documentation Table 5. The fiscal year averages of the sales forecasts for each rate are used to forecast revenues. One further adjustment is made to the sales forecasts for rate development purposes, as described in section 4. The average sales forecast (including the sales for all three rates) over the rate period, including this adjustment, is used to calculate the Network unit cost and in the sales forecast for SCD and GSR.

2.2.3 Sales Forecast for IR Transmission Service

Integration of Resources contracts are transmission service agreements that integrate multiple resources and transmit non-Federal power over BPA's Network and Delivery facilities to multiple points of delivery on the customer's system. With BPA's agreement, firm deliveries may be made to other points on BPA's Network, such as to an intertie. Scheduling non-firm transmission under IR contracts from alternate points of integration or to alternate points of delivery such as to the Southern Intertie may be done at the IR rate up to the contractually specified total transmission demands, subject to the availability of transmission capacity. The transmission demand associated with IR contracts is not transferrable to third parties.

The sales forecast of IR service is the sum of the contract demands in each IR contract. For IR agreements that expire during the rate period, the forecast includes only the revenues associated with the agreements while the agreement is in effect. During the rate period, IR agreements totaling 967 MW will expire. This figure is shown in the reduction in the sales forecast in FY 2014. Documentation Table 4. BPA expects all of the expiring IR agreements to convert to OATT service on the Network. BPA includes expected conversions in the sales forecasts for OATT service on the Network by increasing the PTP sales forecast by the number of megawatts expected to convert to OATT service. These adjustments are made beginning with the month that the IR contract expires.

The sales forecast is shown in Documentation Table 4. The fiscal year averages of the sales forecasts are used to forecast revenues. The average over the rate period is used to develop the Network unit cost and in the sales forecast for SCD and GSR.

2.2.4 Sales Forecast for FPT Service

Formula Power Transmission contracts are transmission service agreements that provide firm transmission of non-Federal power on the Network for both full-year and partial-year service. The forecast of sales of FPT service is the sum of the contract demands in each FPT contract. For FPT agreements that expire during the rate period, the forecast includes only the sales associated with the agreements while the agreements are in effect. During the rate period, FPT agreements totaling 765 MW will expire. This figure is shown in the reduction in the sales forecast in FY 2014 and 2015 in Documentation Table 4. BPA expects the agreements that are expiring to convert to OATT service on the Network. BPA includes expected conversions in the sales forecasts for OATT service on the Network by increasing the PTP sales forecast by the number of megawatts expected to convert to OATT service. The fiscal year averages of the sales forecasts are used to forecast revenues. The sales forecast for FPT is not used to calculate the Network unit cost or in the sales forecast for SCD and GSR, as described in sections 2.4 and 4.1.

2.3 Sales Forecasts for Transmission Service on BPA's Interties

BPA segments the facilities comprising its external interconnections with California/Nevada (Southern Intertie) and Montana (Eastern/Montana Interties) separately from its Integrated Network facilities.

2.3.1 Sales Forecast for IS Transmission Service

BPA offers PTP transmission service on the Southern Intertie. BPA separately forecasts sales of long-term and short-term transmission service on the Southern Intertie.

2.3.1.1 Sales Forecast for Long-Term IS Transmission Service

Forecasts of long-term IS sales include existing and expected long-term sales. The forecast of existing long-term sales is based on:

(a) current confirmed long-term contract demands effective through the FY 2014–2015 rate period; and

(b) confirmed OATT section 17.7 customer deferrals (extensions of commencement of service), which reduce the Intertie sales forecast for the duration of the deferral.

Long-term capacity on the Southern Intertie is fully subscribed, meaning that BPA cannot made additional sales unless existing agreements terminate or are not renewed. As a result, the forecast of additional expected long-term IS sales is based on:

(a) long-term sales that have been requested, such as OATT section 2.2 renewals (associated with existing agreements) and sales that BPA may be able to make if an existing agreement is not renewed; and

(b) expected OATT section 17.7 deferrals during FY 2014–2015 (extensions of commencement of service), which reduce the long-term IS sales forecast for the duration of the deferral.

In developing the long-term IS sales forecasts, BPA examines requests in the queue that are seeking service. BPA also consults with customers, account executives, and other subject matter experts about expected long-term IS requests that could be offered service. BPA receives information on expected service demand, the start date, and the length of the service, and whether the customer will accept the offer. The forecast reflects the most likely scenario based on this information. If there is a great deal of uncertainty in the information gathered through this process, BPA also reviews historical sales to the customer to determine whether to include the additional sales in the forecast.

Table 4 in the Documentation includes the forecasts of confirmed IS sales and expected additional sales for each month of the rate period. Table 4 also shows the total forecast of long-term IS sales (the sum of confirmed sales and expected additional sales), the fiscal year averages, and the averages for the entire rate period. The fiscal year averages are used to forecast revenues, and the average forecast over the rate period is used in the sales forecast for SCD and GSR.

2.3.1.2 Sales Forecast for Short-Term IS Transmission Service

Short-term IS sales are firm or non-firm sales of less than one year and include monthly, weekly, daily, and hourly sales. Because short-term IS service is not reserved far in advance, there are no existing contract demands for this service on which to base the sales forecast. Therefore, the forecast of short-term IS sales expected to occur during the rate period is based on historical short-term sales data and the same market indicators as are used to forecast short-term PTP sales: streamflow, price spread, and seasonality.

The forecast of short-term IS sales is developed using the same three-step process that is used to develop the forecast of short-term PTP sales, with three primary differences. First, the regression used for short-term IS sales compares historical short-term IS sales to the historical streamflow, price spread, and seasonality data, rather than using historical short-term PTP sales data. Second, short-term IS sales to BPA's Power Services and all other customers are modeled with historical streamflow, price spread, and seasonality in the same regression analysis and forecasting model, because there is a correlation between streamflow, price spread, and seasonality and short-term IS sales. Although Power Services is obligated to dispose of the power generated on the Federal Columbia River Power System, regardless of the price, there is a correlation between price spreads and historical short-term IS sales to Power Services. Similarly, the analysis used for forecasting hourly sales and sales under the Block 1 and Block 2 rates to customers other than Power Services in the short-term PTP model is the same analysis used for all customers (Power Services and other customers) in the short-term IS model. Third, whereas the seasonality multiplier applied to short-term PTP sales was highest in the months of March through June, the seasonality multiplier applied to short-term IS sales was highest in the months of March through August. Short-term PTP sales are highest in March through June, while short-term IS sales are highest in March through August.

In all other respects, the process for developing the short-term IS sales forecast is the same as the process for developing the short-term PTP sales forecast, as described in section 2.2.2.2. The forecast of short-term IS sales is shown in Documentation Table 5. The fiscal year averages of the sales forecasts for each rate are used to forecast revenues. One further adjustment is made to the sales forecasts for rate development purposes, as described in section 4. The average sales forecast (including the sales for all three rates) over the rate period, including this adjustment, is used in the sales forecast for SCD and GSR.

2.3.2 Sales Forecast for IM Transmission Service

BPA offers PTP service over its capacity on the Eastern Intertie. The Montana Intertie Agreement between BPA, Avista Corp., NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc., identifies the facilities that constitute the Eastern Intertie (the Townsend-to-Garrison facilities). It also establishes BPA's share of capacity on the Eastern Intertie as any capacity on the line in either direction that is not allocated under the agreement to another party. BPA refers to its capacity as the Montana Intertie and sells the capacity under the IM rate.

The forecast of sales over the Montana Intertie capacity is based on contract demand. The sales forecast over BPA's capacity on the Montana Intertie during the FY 2014–2015 rate period totals 16 MW of existing long-term sales in each year of the rate period. BPA does not forecast any additional long-term IM sales.

Historically, BPA has made very few sales of short-term service on the Montana Intertie and does not expect any short-term sales on the Montana Intertie during the rate period. As a result, the sales forecast for short-term IM service is zero.

The sales forecast for IM service is shown in Documentation Table 4. The fiscal year average sales forecasts are used to forecast revenues, and the average forecast over the rate period is used in the sales forecast for SCD and GSR.

2.4 Sales Forecasts for Ancillary Services: SCD and GSR

BPA provides the Ancillary Services described in section 3 of its OATT. The two ancillary services BPA is required to provide are (1) Scheduling, System Control, and Dispatch Service, and (2) Reactive Supply and Voltage Control from Generation Sources Service. The sales forecasts for these Ancillary Services are discussed below.

SCD service is necessary for the provision of basic transmission service within BPA's balancing authority area (the area in which the responsible entity, or balancing authority, must maintain a balance between generation and load (consumption)). System control and communications equipment and dispatch of generating resources and transmission facilities maintain generation and load balance, maintain physical and electronic security requirements for North American Electric Reliability Corporation Critical Infrastructure facilities, and preserve system reliability for all transactions. SCD service can be provided only by the operator of the balancing authority area in which the transmission facilities used are located, since the service is used to schedule the movement of power through, out of, within, or into the balancing authority area.

GSR Service also is necessary for the provision of basic transmission service within BPA's balancing authority area. GSR is the provision of reactive power and voltage control by generating facilities under the control of BPA as the operator of the balancing authority area. The GSR rate is set on a quarterly basis according to a formula in the GSR rate schedule.

Because all transmission customers must purchase SCD and GSR, the sales forecast for both services is the sum of the sales forecasts of all transmission services (for NT customers, BPA uses the coincident peak load forecast), with one exception. The FPT sales forecast is not included in the SCD and GSR sales forecast, because the FPT rate includes the costs of the SCD and GSR services associated with FPT service. Therefore, the FPT revenues that recover SCD and GSR costs are removed from the SCD and GSR revenue requirement before rates are calculated.

The short-distance discount associated with NT and PTP service does not apply to SCD and GSR sales, and as a result, the sales forecast for SCD and GSR is not adjusted to reflect the SDD. The sales forecast used for developing the SCD rate is shown in Documentation Table 10. The same sales forecast is included in the formula in the GSR rate schedule. *See* Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, ACS-14, section II.B.

For purposes of developing revenue forecasts, BPA does not separately forecast sales for SCD and GSR. Instead, the SCD and GSR rates are applied to the sales forecast for long-term and short-term PTP, IS, and IM service and to the load forecast for NT service. The IR rate developed in this Study incorporates the SCD and GSR rates developed here. Therefore, BPA does not separately forecast SCD or GSR revenue associated with IR service. IR revenue includes the revenue from those services. See Documentation Table 12.

2.5 Sales Forecast for Utility Delivery Service

Utility Delivery service applies to utility customers that take delivery of power over the Utility Delivery segment, which includes transmission facilities at voltages below 34.5 kV. Sales forecasts of Utility Delivery service are based on load forecasts, because the charges for this transmission service are based on the customers' load. BPA forecasts sales for this service using POD load forecasts. The POD load forecast for Utility Delivery service is developed in the same manner as is described in section 2.2.1 for the load forecasts for NT service, except that BPA calculates the POD load forecast over the FY 2014–2015 rate period for Utility Delivery customers that take NT service, as well as the single Utility Delivery customer that takes PTP service. BPA uses the average of the total monthly Utility Delivery POD load forecasts over the FY 2014-2015 rate period to calculate the Utility Delivery rate, which is discussed in greater detail in section 7.4.1. The annual sales forecasts are shown in Documentation Table 9. For the Utility Delivery revenue forecast, the Utility Delivery customers' monthly POD load forecast is multiplied by the proposed Utility Delivery rate for each month in the rate period.

2.6 Revenue Forecasts

The transmission revenue forecasts determine the expected levels of revenue from transmission and ancillary services rates and other sources for the rate period. See Documentation Table 12. As discussed above, this Study forecasts revenues at current rates and at proposed rates to perform the current revenue test and the revised revenue test. The forecast of revenue at current rates applies the transmission and ancillary services rates placed into effect on October 1, 2011, to the sales forecasts. The forecast of revenue at proposed rates applies the final rates to the sales forecasts. The forecasts are used to test whether the current and proposed rates are sufficient to recover the transmission revenue requirement. The Transmission Revenue Requirement Study, BP-14-FS-BPA-08, further describes the revenue tests.

Both revenue forecasts include revenue credits. Section 3 of this Study discusses revenue credits in detail. In general, revenue credits are revenues from sources other than the transmission rates determined in this rate proceeding. The Study includes revenue credits in the revenue forecasts to ensure that the revenue tests performed in the Transmission Revenue Requirement Study incorporate all sources of transmission-related revenue. Table 12 in the Documentation includes all of the revenue credits applied in the revenue forecast.

2.6.1 Forecast of Non-Cash Revenues: Transmission Credits and Interest Expense Associated with Customer-Financed Projects

A portion of the revenues that BPA forecasts is non-cash revenues due to credits that customers receive against their transmission service charges. (BPA provides these credits in two general circumstances, described below.) The credits (non-cash revenues) are forecast as part of this Study and are included in the revenue forecasts discussed above because the transmission services to which they apply are included in the sales forecasts. However, because BPA does not receive the revenue in the form of cash, the credit (and the related interest expense, described below) have a different impact on BPA's revenue requirements and cost recovery than cash revenue. *See* Transmission Revenue Requirement Study, BP-14-FS-BPA-08, section 2.3.5.

BPA forecasts transmission credits and related interest expense associated with generator interconnection agreements and the California-Oregon Intertie (COI) upgrade project. Under the generator interconnection agreements, interconnection customers advance fund Network Upgrades (upgrades to the transmission system at or beyond the point at which the interconnection facilities connect to the transmission system) if BPA, as the transmission provider, does not provide the funding. The advance funds are then returned to the customers, with interest, either as credits to the customers' transmission bills or as monthly cash payments. The credits are applied to transmission service used to transmit power from the generating facility. The cash payments are designed to approximate the comparable credits and are based on the generating facility's capacity and its plant capacity factor. The customer chooses whether to receive credits or cash payments.

BPA also provides transmission credits for customer financing for the COI upgrade. The upgrade increased the availability of the COI and Pacific DC Intertie (PDCI) so that BPA is able to provide long-term firm transmission service up to the full rating of the COI and PDCI. The forecasts of transmission credits and related interest expense include the transmission credits related to the COI upgrade and transmission credits related to generator interconnection agreements.

The forecasts of transmission credits and related interest expense at current rates and at proposed rates are provided in Documentation Tables 17.1 and 17.2.

3. REVENUE CREDITS AND ADJUSTMENTS TO THE SEGMENTED REVENUE REQUIREMENTS

To develop the revenue requirements for use in calculating rates, the Study allocates revenue credits among the various segments and then applies these credits and other adjustments to the segmented revenue requirements determined in the Transmission Revenue Requirement Study. These revenue credits and adjustments reflect known costs and revenues that are not accounted for in the Transmission Revenue Requirement Study. This Study identifies the net segmented revenue requirements that result from application of the revenue credits and adjustments as rate development costs.

3.1 Revenue Credits

Revenue credits are transmission revenues from sources other than the general transmission rates developed in the rate proceeding. Revenue credits include revenue from items such as fixed-price contracts, contracts that specify the rates for services, Use-of-Facilities contracts, and fixed-price fees. The Study forecasts revenue credits based on existing contract charges or rates, expectations of additional sales at such charges or rates, and receipt of fixed-price fees.

The revenue credits for fixed-price contracts and fees relate to items such as fiber and wireless leases (over installed communications capacity that exceeds BPA's operational needs), land leases, reservation and application fees, direct funding of projects and facilities, and O&M charges. The Use-of-Facilities contracts that generate non-rate revenue include agreements such as those governing the Montana Intertie and the

Eastern Intertie, DSI delivery contracts, and capacity ownership agreements on the Southern Intertie, under which parties pay for the rights to a capacity share of the available transmission.

The segmented revenue requirement is initially set without regard to these additional revenues. The Study allocates revenue credits to particular segments, which reduces the segmented revenue requirements and ensures that the Study accounts for all sources of revenue in determining the segmented revenue requirements used to calculate rates. If the Study did not account for the revenue represented by the revenue credits, the rates would be higher than needed to recover costs. The allocation and application of the revenue credits described in this section are separate and distinct from the inclusion of the revenue credits in the revenue forecasts discussed in section 2.

The Study allocates revenue credits associated with a particular transmission segment entirely to that segment. For example, revenues related to the O&M charges for customers using facilities on the Southern Intertie are allocated entirely to the Southern Intertie. If revenue credits are not associated with a particular segment, the revenues are allocated across all segments based on the ratio of net plant investment in each segment to the total plant investment. For example, the Study allocates revenues from fiber and wireless leases to all segments as a revenue credit. Documentation Table 2 identifies all of the expected revenue credits from various sources and the allocation of the credits by segment.

3.2 Adjustments to the Segmented Revenue Requirements

The Study includes certain adjustments to the segmented revenue requirements. These adjustments are not categorized as revenue credits because they do not account for additional revenues. In general, the adjustments allocate revenues or costs that are not otherwise recovered by the segmented revenue requirements and apply the allocated amount as an adjustment to the segmented revenue requirement

3.2.1 Eastern Intertie Adjustment

The Eastern Intertie segment includes the Townsend-Garrison transmission (TGT) lines and a portion of the Garrison substation facilities. Transmission Segmentation Study, BP-14-FS-BPA-06, section 2.4. BPA constructed these facilities under provisions of the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which address constructing transmission lines and providing transmission service for the Colstrip generating facility in Montana. As part of the agreement, Avista, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy (or their predecessors) purchased a portion of the capacity of BPA's Townsend-to-Garrison line. BPA receives payments from each party for its share of the Townsend-to-Garrison capacity under the TGT rate. BPA may market any remaining transmission capacity in either direction on the Eastern Intertie.

As explained below, the total revenues allocated to the Eastern Intertie segment exceed the net segmented revenue requirement. The Study allocates these excess revenues to the other segments and applies the allocated amount as an adjustment that reduces the segmented revenue requirements.

The adjustment for the Eastern Intertie Segment is based on the net segmented revenue requirement of the segment. To determine the net segmented revenue requirement, the Study applies revenue credits and the revenues associated with the IM rate to the segmented revenue requirement from the Transmission Revenue Requirement Study. Application of the revenue credits and other revenues allocated to the segment offsets revenue requirements so that rates are set no higher than necessary to recover the relevant costs.

Documentation Table 2 shows the expected revenue credits that apply to the Eastern Intertie segment. The most significant revenue credit relates to revenue from the payments to BPA under the Montana Intertie Agreement for rights to transmission service on the TGT transmission lines. These payments are fixed by contract and total $12.4 million annually during the rate period. The Study applies the entire amount of this revenue credit to the Eastern Intertie segment.

The Study also allocates to the Eastern Intertie Segment the revenues from sales under the IM rate. The IM rate applies to PTP transmission service on BPA’s capacity share of the Eastern Intertie. Revenues from these sales are forecast to total $0.12 million annually during the rate period, and the Study allocates this entire amount to the Eastern Intertie segment. Documentation Table 3.

The segmented revenue requirement for the Eastern Intertie averages $9.92 million annually. See Documentation Table 1. After applying all of the revenue credits and the IM rate revenues to the Eastern Intertie's segmented revenue requirement, the result is that forecast revenues for the Eastern Intertie segment exceed the net segmented revenue requirement by $3.6 million annually. Documentation Table 3. This is primarily because some costs are allocated to this segment based on the net plant investment ratios determined in the Transmission Segmentation Study, and net plant investment is affected by depreciation. Depreciation of the facilities segmented to the Eastern Intertie reduces the revenue requirement for the segment, while payments under the Montana Intertie Agreement remain fixed.

The Study allocates the excess revenue from the Eastern Intertie segment to all the other segments proportionally based on net plant investment determined in the Transmission Segmentation Study. Transmission Segmentation Study Documentation, BP-14-FS-BPA-06A, Table 2. This reduces the difference between the Eastern Intertie segment's adjusted revenue requirement and revenue recovery to zero. Transmission Rates Study Documentation, BP-14-FS-BPA-07A, Table 3. The Study then applies the amount of the excess revenue allocated to each segment as an adjustment to reduce the revenue requirement for each segment.

3.2.2 DSI Delivery Adjustment

The DSI Delivery segment consists of low-voltage transmission facilities that provide transmission service to DSI customers. Charges for service on the DSI Delivery segment are established by contract and change based on a schedule incorporated in those contracts. As a result, the Study does not calculate a rate that is specific to delivery service on DSI facilities. See section 7.

Although the Study does not calculate a rate for service on the DSI Delivery segment, it does account for the revenues and costs associated with this segment. The revenues generated from sales under the DSI Delivery contracts and the other revenue credits allocated to this segment are forecast to total $2.81 million annually during the rate period. Documentation Table 3. The Eastern Intertie Adjustment allocates an annual average of another $16,000 in revenue to this segment. The revenue credits and adjustment reduce the segmented revenue requirement for the DSI Delivery segment.

The average annual segmented revenue requirement attributable to the DSI Delivery segment is $3.38 million. Documentation Table 1. After applying the revenue credits, the adjustment for the Eastern Intertie revenue, and the Utility Delivery adjustment, the remaining costs associated with the DSI Delivery segment average $0.58 million annually during the rate period.

As described above, the rates for DSI Delivery Service are not being reset in this proceeding because the charges for that service are established by contract. As a result, the forecast revenues associated with the DSI Delivery segment are insufficient to recover the $0.58 million in excess costs. The DSI Delivery Adjustment accounts for recovery of these costs by allocating them to other segments based on the net plant investment ratios from the Transmission Segmentation Study. Transmission Segmentation Study Documentation, BP-14-FS-BPA-06A, Table 2. The Study does not allocate a portion of the DSI Delivery costs to the Eastern Intertie or Utility Delivery segments.

3.2.3 Utility Delivery Adjustment

Section 7 discusses how BPA calculates the rate for the Delivery Charge for service on Utility Delivery facilities. This calculation includes a limit on the increase in this rate due to concerns about rate shock. Because of this limit, Utility Delivery segment costs are not fully recovered through the Utility Delivery rate. The Utility Delivery Adjustment allocates to the other segments Utility Delivery segment costs that are not recovered in Utility Delivery rates. Documentation Table 3. Utility Delivery segment costs are not allocated to the Eastern Intertie segment; see section 3.2.2.

3.2.4 Adjustment for NT Redispatch Costs

Under Attachment M to BPA's OATT, Transmission Services initiates redispatch of Federal resources as part of congestion management efforts on the Network. There are three levels of redispatch that Transmission Services can request from Power Services under Attachment M to relieve flowgate congestion: Discretionary Redispatch, NT Firm Redispatch, and Emergency Redispatch. The forecast of costs for FY 2014-2015 for Discretionary Redispatch is $50,000 per year; the forecast for NT Firm Redispatch of Federal resources is $350,000 per year; and the forecast for Emergency Redispatch is $0 per year. Generation Inputs Study, BP-14-E-BPA-05, section 7.

The Study also forecasts costs associated with the redispatch of NT customers' non-Federal resources. This is referred to as non-Federal NT redispatch. The cost of non-Federal NT redispatch for FY 2014-2015 is $80,000 per year.

As described in the Transmission Revenue Requirement Study Documentation, the total forecast costs of NT redispatch are included in the segmented revenue requirement for the Network. The Study reduces the Network segment revenue requirement by the costs of NT Firm Redispatch and non-Federal NT redispatch and allocates those costs to the rates for NT service. BPA implements these types of redispatch to avoid curtailment of NT service; therefore, they benefit only NT customers. To ensure that these costs are allocated to NT customers and not to other Network users, the Study applies a credit for the cost of these types of redispatch to the Network segment in each year of the rate period and includes the costs in the calculation of NT rates. Section 4 discusses calculation of the NT rates.

3.3 Allocation of Generation Integration Revenues

The Generation Integration segment consists of transmission facilities that integrate Federal resources into BPA's Network. The cost of the Generation Integration segment, after all revenue credits and adjustments are applied, averages $9.5 million annually over the rate period. Documentation Table 3. These costs are assigned to BPA Power Services and recovered through power rates. The payments that Power Services makes to Transmission Services are a revenue credit in the transmission revenue forecast and are applied to the Generation Integration segment.

4. NETWORK TRANSMISSION SERVICES

BPA establishes separate rates for four types of transmission service on its Integrated Network: Network Integration Transmission Service, Point-to-Point Transmission Service, Integration of Resources, and Formula Power Transmission. BPA provides NT and PTP service pursuant to the terms and conditions set forth in its OATT, and it provides FPT and IR service under legacy (or grandfathered, pre-FERC Order 888) agreements.

In general terms, the Study calculates the rates for Network Services by taking the net segmented revenue requirement for the Network segment, subtracting the forecast revenues associated with FPT service, and allocating a proportionate share of the resulting revenues to NT, PTP, and IR service. The rates for FPT service are based on certain simplifying assumptions described in section 4.5. The rates for NT, PTP, and IR service are calculated by dividing the costs to be recovered by those services by the NT, PTP, and IR billing determinants, respectively.

4.1 Network Segment Cost Allocation

To calculate the rates for Network services, the Study allocates the adjusted Network segment revenue requirement among the various services. The Study takes the annual average Network segment revenue requirement, $653.43 million, and applies revenue credits and adjustments. These revenue credits and adjustments are described in section 3 of the Study. Documentation Table 3. Application of the revenue credits and adjustments results in an adjusted Network segment revenue requirement of $632.03 million. Documentation Tables 1 and 3.

As explained in section 4.5, FPT service is provided under contracts that address specific classifications of Network transmission facilities, and FPT rates separately recover a subset of Network costs. Therefore, the Study subtracts from the adjusted Network segment revenue requirement $19.90 million in forecast annual revenue attributable to sales of FPT service on the Network. Documentation Table 7. Subtracting the forecast FPT revenues excludes the costs and revenues attributable to FPT service from the costs allocated among NT, PTP, and IR service, thus ensuring that rates for NT, PTP, and IR service are based only on costs and revenues properly attributable to the services. Subtracting the forecast FPT revenue results in an annual average cost of $612.14 million to be allocated among NT, PTP, and IR service. Documentation Table 7.

The Study allocates costs to PTP and IR service based on contract demand and to NT service based on forecast load. The NT load forecast is based on a 12 NCP measure. See section 2. The Study calculates an allocation percentage for each service based on the ratio of the forecast for each individual service to the total forecast average annual sales for all three services, 34,479 MW. Documentation Table 7. The allocation percentages for NT, PTP, and IR services are 20.91 percent, 77.15 percent, and 1.94 percent, respectively. Documentation Table 7. Multiplying the total adjusted average annual Network revenue requirement of $612.14 million by the sales percentage for each service yields an allocated cost of $127.99 million for NT service, $472.27 million for PTP service, and $11.88 million for IR service. Documentation Table 7. The Study uses these allocated costs to calculate the rates for NT, PTP, and IR service.

4.2 Network Integration Rate (NT-14)

Network Integration service provides transmission service for a customer's designated network load, including network load growth. BPA provides this service according to the terms and conditions in Part III of its OATT.

The NT-14 rate schedule identifies a single rate for NT Service and NT Conditional Firm Service under the OATT. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, NT-14, section II. The monthly billing factor for the NT-14 rate is the customer's Network load on the hour of the Monthly Transmission System Peak Load for the month (the billing period). NT-14 Rate Schedule, section III.A.

The NT-14 rate schedule includes a variety of adjustments and references to charges from other rate schedules. The rate schedule includes an SDD available to customers with designated Network Resources that use less than 75 circuit miles of BPA's transmission facilities for delivery to Network Load. NT-14 Rate Schedule, section IV.E. The SDD is a credit applied to the customer's monthly bill according to the following formula:

$$\text{SDD credit} = \text{NT Rate} \times \text{Average HLH Generation} \times (75 - \text{distance}) / 75 \times 0.4$$

For resources that are directly connected to the customer's system or that do not use any FCRTS facilities, the discount is 40 percent of the NT rate multiplied by the average generation of the resource during heavy load hours.

Other charges and notices in the NT-14 rate schedule include:

- a requirement to purchase Scheduling and Reactive ancillary services
- the Delivery Charge
- the Power Factor Penalty Charge
- the Failure to Comply Penalty Charge
- notice that BPA will collect capital and related costs of a Direct Assignment Facility under the Advance Funding rate or Use-of-Facilities rate
- notice of BPA's intent to charge incremental cost rates under specified conditions
- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act

NT-14 Rate Schedule, section IV. Study section 7 discusses the rate schedule provisions.

To calculate the NT rate, the Study adds the $127.99 million in Network costs allocated to NT service to the NT redispatch costs ($350,000 in NT Firm Redispatch of Federal resources costs and $80,000 in non-Federal NT redispatch costs), which equals total costs of $128.42 million. Documentation Table 7. Dividing this amount by the NT billing factor of 6,148 MWs yields a unit cost of $20,886/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $20.89/kW-year. *Id.* The kW-year unit cost is divided by 12 to yield the rate for NT service, which is $1.741/kW-month. *Id.*

4.3 Point-to-Point Rate (PTP-14)

Point-to-Point transmission service provides for the transmission of energy on a firm, non-firm, or conditional firm basis from specific points of receipt to specific points of delivery on the transmission system. BPA provides this service according to the terms and conditions in Part II of its OATT.

The PTP-14 rate schedule includes rates for long-term service; monthly, weekly, and daily service; and hourly service. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, PTP-14, section II. A single rate applies to all long-term firm service and to conditional firm service under the rate schedule. The rate schedule includes two rates for monthly, weekly, and daily service: "Block 1" for the first five days of a reservation, and "Block 2" for the remaining days of the reservation. For reservations longer than five days, the Block 1 rate applies to the first five days of the reservation, and the Block 2 rate applies to the remaining days of the reservation. One hourly rate applies to all hours of a reservation for hourly service. PTP-14 Rate Schedule, section II.

The PTP-14 rate schedule also incorporates a variety of adjustments, charges, notices, and other rate provisions, including:

- a Short-Distance Discount for contract paths less than 75 circuit miles

- a requirement to purchase Scheduling, System Control, and Dispatch Ancillary Service
- the Delivery Charge
- the Power Factor Penalty Charge
- an Unauthorized Increase Charge
- the Reservation Fee
- the Failure to Comply Penalty Charge
- a credit for interruption of daily non-firm service
- notice that BPA will collect capital and related costs of a Direct Assignment Facility under the Advance Funding rate or Use-of-Facilities rate
- notice of BPA's intent to charge incremental cost rates under specified conditions
- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act

PTP-14 Rate Schedule, section IV. See Study section 7 for further discussion of the rate schedule provisions.

The Study calculates the rate for long-term firm PTP service by dividing the Network costs allocated to PTP service, $472.27 million, by the forecast average annual PTP sales of 26,601 MW, yielding a unit cost of $17,754/MW-year. Documentation Table 7. This amount is then divided by 1,000 to derive a kW-year unit cost of $17.75/kW-year. *Id.* This kW-year unit cost is divided by 12 to yield the monthly rate for long-term PTP service, $1.479/kW-month. *Id.*

The rate for short-term and hourly PTP service is derived from the long-term rate. Short-term sales allow the customer to purchase transmission that more closely matches the energy required on a day-by-day or hour-by-hour timeframe. Typically, this means more short-term transmission is purchased during weekdays than weekends and during heavy load hours than during light load hours (LLH).

In order to account for the greater amount of short-term capacity that is expected to be sold during weekdays and heavy load hours, and to help ensure that the rate for sales during those hours recovers the appropriate amount of costs, the Study sets short-term rates at a level higher than a simple pro rata fraction of the long-term rate. It does so by establishing the Block 1 rate for the first five days of short-term daily service based for the costs for a full seven days. The Study calculates the Block 1 rate by multiplying the daily PTP unit cost (*i.e.*, the annual rate divided by 365) by a factor of 7/5 (seven total days in the week divided by five weekdays). The Block 2 rate is set equal to the daily unit cost with no adjustment to the rate.

The Study applies a similar factor in the calculation of the rate for hourly service. Since there are 16 heavy load hours each weekday, the hourly rate is set by multiplying the PTP unit cost by an LLH/HLH factor of 24/16 (24 hours per day divided by 16 heavy load hours) and then by the 7/5 daily factor.

In the calculation of the PTP unit cost , the forecast of short-term sales in the denominator is adjusted upward by these same LLH/HLH factors for rate development purposes, to recognize that the short-term rates will recover more revenue because the rates are set higher by these factors. The final short-term PTP sales forecasts after these adjustments are used in the development of the rates and in the revenue forecasts.

The Study calculates the daily PTP short-term Block 1 rate by dividing the annual PTP unit cost by 365 days and multiplying by the LLH/HLH factor of 7/5. Documentation Table 7. The resulting Block 1 rate is $0.068/kW-day. The daily PTP short-term Block 2 rate of $0.049/kW-day is calculated by dividing the unit cost by 365 days. *Id.* The PTP daily, weekly, and monthly services are all charged the same block rates.

The hourly PTP rate of 4.26 mills/kWh, which is applied to both firm and non-firm hourly sales, is calculated by dividing the annual PTP unit cost by 8,760 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 and 7/5. *Id.*

4.4 Integration of Resources Rate (IR-14)

As described in section 2, IR contracts integrate multiple resources and transmit non-Federal power over BPA’s Network and Delivery facilities to multiple points of delivery on the customer’s system. The rate that applies to service under IR agreements includes a single “postage stamp” rate (it does not vary by distance) that combines a monthly demand charge equal to the Network unit cost and a charge for SCD Service. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, IR-14, section II.A. The IR rate schedule also provides for a charge for GSR.

IR contracts include specified transmission demands at each point of integration, which are based on the annual peak output of a generating resource or annual peak demand in a power purchase agreement. The billing factor for the IR demand charge is the contractually specified transmission demand or, if the contract contains multiple points of integration and transmission demands, the total transmission demand, which is the sum of the multiple transmission demands under the contract. Non-firm service in excess of the total transmission demand is billed at the PTP rate.

The IR rate schedule includes an SDD for IR contracts, which decreases the IR rate by up to 40 percent for transmission that uses Network facilities for a distance of less than 75 circuit miles. IR-14 Rate Schedule, section II.B. No IR contracts are expected to be subject to the SDD during the rate period.

The IR rate schedule also incorporates other rate provisions and potential adjustments:

- the Power Factor Penalty Charge
- the Delivery Charge
- the Failure to Comply Penalty Charge
- provisions detailing the circumstances under which the ratchet demand may be waived or reduced

Study section 7 explains the rate provisions in detail.

The Study calculates the IR rate by dividing the Network costs allocated to IR service, $11.88 million, by the forecast average annual IR sales of 669 MW, yielding a unit cost of $17,754/MW-year. Documentation Table 7. This amount is divided by 1,000 to derive a kW-year unit cost of $17.75/kW-year. *Id.* This kW-year unit cost is divided by 12 to yield a monthly unit cost of $1.479/kW-month. *Id.*

The costs of providing IR service include the Network transmission costs and the costs of SCD and GSR services, which are the required ancillary services. The IR base rate is calculated by combining the monthly IR service unit cost of $1.479/kW-mo with the SCD rate of $0.257/kW-month, for a total IR rate of $1.736/kW-month. The IR-14 rate schedule provides for adding the rate for GSR service to the IR base rate as well. As explained in section 6, however, the GSR rate has been set at zero, so it has no impact on the charges for IR service.

4.5 Formula Power Transmission Rates (FPT-14.1 and FPT-14.3)

The FPT-14.1 rate schedule applies to Formula Power Transmission contracts that allow annual rate adjustments. The FPT-14.3 rate schedule applies to FPT contracts that allow rate changes once every three years.

The FPT rates are generally based on the types of transmission facilities used under a particular FPT contract and the distance the energy is transmitted. The rate schedules include charges for use of facilities that are part of the main grid (that portion of the Network facilities with an operating voltage of 230 kV or more) and for those that are part of the secondary system (that portion of the Network with an operating voltage between 69 kV and 230 kV). Transmission, Ancillary and Control Area Service Rate

Schedules, BP-14-E-BPA-10, FPT-14.1, section II, and FPT-14-3, section II. Within the category of facilities designated as "main grid" facilities, there are specific charges for use of main grid interconnection terminals, main grid terminals, and main grid miscellaneous facilities. The secondary system charges are divided into charges for use of secondary system transformation, secondary system intermediate terminals, and secondary system interconnection terminals. FPT-14.1 and FPT-14.3 Rate Schedules, section II.

The distance charge has two components: a charge for the distance energy is transmitted over the main grid, and a charge for the distance energy is transmitted over the secondary system. FPT-14.1 and FPT-14.3 Rate Schedules, section II. Each FPT contract will have a different overall rate per unit of transmission demand based on the facilities used under the contract and the distance energy is transmitted.

The FPT rate also includes the costs associated with SCD and an adjustment for the GSR charge. FPT-14.1 and FPT-14.3 Rate Schedules, section II. The rate schedule specifies that customers taking FPT service are subject to the Power Factor Penalty Charge and the Failure to Comply Penalty Charge. FPT-14.1 and FPT-14.3 Rate Schedules, section IV. Section 7 discusses these rate schedules.

Only six customers are expected to take FPT service during the rate period, and the sales under the few remaining FPT contracts are forecast to constitute about 3 percent of BPA's Network revenues. In addition, of the 1,548 MW under FPT contracts expected to be in effect at the beginning of FY 2014, 565 MW will expire by the end of FY 2014, and an additional 200 MW will expire by the end of FY 2015. Documentation Table 4. Given the relatively small effect of the FPT contracts on BPA's revenues, the Study relies on certain simplifying assumptions in order to set the FPT-14 rates, instead of a detailed cost analysis of all the categories and sub-categories of facilities in the FPT rate schedule.

The Study assumes that the increase in FPT costs will equal the increase in the sum of the PTP service unit cost (determined in section 4.3) and the rates for the associated ancillary services. The Study also assumes that the costs for each of the various FPT rate components (*e.g.*, Main Grid Distance, Main Grid Terminal) will maintain the same proportion to each other that exists in the FPT-12 rates. The facilities used to provide FPT service and associated ancillary services are the same type of facilities used to provide other services over the Network segment. As a result, it is reasonable to assume that their costs accelerate at similar rates and in relation to one another.

The increase in the PTP service unit cost plus the associated ancillary services is 15.7 percent. Documentation Table 6. As a result, the Study sets the FPT-14 rates by increasing each of the current FPT rate components by 15.7 percent. The resulting FPT component rates are identified in Documentation Table 11. Any differences in the percentage increase for each individual component are due to rounding the rate for that component.

The forecast revenue from the existing FPT contracts at FY 2012–2013 rates is $20.19 million. Documentation Table 11. Dividing the forecast revenue at FY 2012–2013 rates by the sales forecast for FY 2014-2015 results in an average FPT rate of $1.440/kW-mo. Applying the increase in the unit cost plus the associated ancillary services of 15.7 percent to the revenues at current rates results in an average FPT rate of $1.666/kW-mo. The average FPT rate is the denominator for the adjustment for GSR.

Multiplying the sales forecast by the average FPT rate yields a revenue forecast of $23.36 million. The unit cost of the Network component of the rates is 85.2 percent of the sum of the unit cost, the SCD rate, and the GSR rate, as shown on Documentation Table 6. Applying this percentage to the FPT revenue forecast produces $19.90 million attributable to Network transmission service excluding ancillary services. This amount of revenue is allocated to covering Network costs. The remaining revenues of $3.46 million are attributed to ancillary services and are allocated to cover SCD costs, as shown in Documentation Table 10.

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5. INTERTIE TRANSMISSION SERVICES

BPA provides Point-to-Point transmission service on the Southern Intertie and the Eastern Intertie. As described below, the Study develops separate rates for service on the facilities comprising these interties.

5.1 Southern Intertie Point-to-Point Rate (IS-14)

The IS-14 rate schedule applies to PTP service on the Southern Intertie. The IS rate schedule includes rates for long-term firm service; monthly, weekly, and daily service; and hourly firm service. A single rate applies to all long-term firm service under the rate schedule. Like the PTP-14 rate schedule, the IS-14 rate schedule provides for daily, weekly, and monthly transmission service at daily Block 1 and daily Block 2 rates. One hourly rate applies to all hours of a reservation for hourly service. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, IS-14, section II.

The IS rate schedule also includes these provisions:

- the requirement to purchase certain ancillary services
- a credit for interruption of daily non-firm service
- the Reservation Fee
- the Power Factor Penalty Charge
- an Unauthorized Increase Charge
- the Failure to Comply Penalty Charge
- notice of BPA's intent to charge incremental cost rates under specified conditions

- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act
- notice regarding Direct Assignment Facility costs, which are to be collected under the Advance Funding rate or Use-of-Facilities rate

Id. section IV. See section 7 below for further discussion of the rate schedule provisions.

To calculate the IS-14 rates, the Study first determines a unit cost for service on the Southern Intertie. The unit cost equals the net segmented revenue requirement for the Southern Intertie Segment divided by the forecast sales for the segment. To determine the net segmented revenue requirement, the Study applies revenue credits and adjustments to the segmented revenue requirement determined in the Transmission Revenue Requirement Study, BP-14-FS-BPA-08. Section 3 of the Study describes these revenue credits and adjustments.

The Southern Intertie was originally constructed in 1967 and was expanded in 1993 with the participation of non-Federal parties (the capacity owners). The capacity owners obtained a share of the capacity on these facilities and make payments to BPA for use of the capacity. The Study treats revenue from the payments by the capacity owners as a revenue credit allocated to the Southern Intertie, which reduces the segmented revenue requirement. Documentation Table 3.

After all revenue credits and adjustments are applied, the net segmented revenue requirement for the Southern Intertie segment is $85.90 million. *Id.* The projected sales on BPA's portion of the Southern Intertie equal 6,345 MW. *Id.* Table 8. Dividing dollars by megawatts yields annual rate of $13.54/kW-year. *Id.* This annual rate is divided by 12 to determine the IS long-term rate of $1.128/kW-month.

The calculation of the daily and hourly IS-14 rates includes the same adjustment for short-term sales that the Study makes for the PTP rates. Section 4.3 explains that adjustment. The daily IS short-term Block 1 rate is calculated by dividing the annual rate, $13.54/kW-year, by 365 days/year and multiplying by the LLH/HLH factor of 7/5, which yields $0.052/kW-day. *Id.* The daily IS short-term Block 2 rate is calculated by dividing the annual rate by 365 days, yielding $0.037/kW-day. *Id.*

The IS hourly rate applies to both firm and non-firm hourly sales. It is calculated by dividing the annual rate by 8,760 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 and 7/5. *Id.* The result is a IS-14 hourly rate of 3.25 mills/kWh.

5.2 Eastern Intertie (Montana)

The Broadview-to-Garrison intertie facilities, referred to as the Montana Intertie, were built to move the output of the Colstrip generating facility, a coal plant in Montana, to the Pacific Northwest. The arrangement for constructing transmission lines and providing transmission service for Colstrip was set forth in the Montana Intertie

Agreement. The Colstrip parties to the Montana Intertie Agreement (Avista, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy, or their predecessors) built transmission facilities between Broadview and Townsend, Montana. BPA built the facilities between Townsend and Garrison, which it calls the Eastern Intertie. Under the Montana Intertie Agreement, BPA provides transmission service at the TGT rate to each Colstrip party on BPA's Townsend-to-Garrison line. BPA may market any remaining transmission capacity in either direction on the Eastern Intertie at the IM rate.

The costs associated with the Eastern Intertie segment are primarily recovered through the Montana Intertie Agreement under the TGT rate, which is a formula rate specified in the contract. BPA receives payments under the TGT rate from each Colstrip party for its share of the costs of the Townsend-to-Garrison capacity. These payments are a revenue credit applied to the Eastern Intertie segmented costs. Documentation Table 2. Non-firm service for the Colstrip parties is available over the Eastern Intertie under either the IE or IM rates. A proportionate share of any revenue for non-firm service received under the IE and IM rates is credited under the TGT rate to the Colstrip parties. Any firm sales BPA makes on BPA's remaining capacity on the Eastern Intertie are marketed at the IM rate.

5.2.1 Montana Intertie Rate (IM-14)

The IM-14 rate applies to service on BPA's capacity share of the Eastern Intertie facilities. The IM rate schedule includes rates for long-term firm service; monthly, weekly, and daily service; and hourly firm service. Like the PTP-14 rate schedule, the IM-14 rate schedule provides blocked rates for monthly, weekly, and daily firm and non-firm service. One hourly rate applies to all hours of a reservation for hourly service. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, IM-14, section II.

The IM rate schedule also includes these provisions:

- the requirement to purchase certain ancillary services
- a credit for interruption of daily non-firm service
- the Reservation Fee
- an Unauthorized Increase Charge
- the Failure to Comply Penalty Charge
- notice of BPA's intent to charge incremental cost rates under specified conditions
- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act
- notice regarding Direct Assignment Facility costs, which are to be collected under the Advance Funding rate or Use-of-Facilities rate

Id. section IV. See section 7 for further discussion of the rate schedule provisions. The IM rate is based on BPA's proportionate share of the costs of the Townsend-to-Garrison facilities as identified in the Montana Intertie Agreement. BPA forecasts 16 MW of long-term sales over BPA's capacity during the rate period. Documentation Table 8.

The IM-14 annual rate is calculated by dividing the BPA cost under the Montana Intertie Agreement by the BPA capacity allocation of 16 MW, which yields $7.18/kW-year. *Id.* The monthly IM-14 rate is calculated by dividing the annual rate by 12 months, yielding $0.598/kW-mo. *Id.*

The calculation of the daily and hourly IM-14 rates includes the same adjustment for short-term sales that the Study makes for PTP rates. Section 4.3 explains the reasons for that adjustment. The daily IM-14 short-term Block 1 rate is set by dividing the IM-14 annual rate by 365 days and multiplying by the LLH/HLH factor of 7/5, which yields $0.028/kW-day. *Id.* The daily IM short-term Block 2 rate is calculated by dividing the IM-14 annual rate by 365 days, yielding $0.020/kW-day. *Id.*

The IM hourly rate, applied to both firm and non-firm hourly sales, is calculated by dividing the IM-14 annual rate by 8,760 hours (per year), dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 and 7/5. *Id.* The result is an IM-14 hourly rate of 1.72 mills/kWh. *Id.*

5.2.2 Townsend-Garrison Transmission Rate (TGT-14)

As described above, the BPA recovers its costs of the Eastern Intertie through the TGT rate, which is a formula rate that is based on provisions of the Montana Intertie Agreement. The TGT rate schedule is Exhibit E to the agreement and has been modified in minor respects in rate proceedings held since execution of the agreement. The TGT revenues are reflected as a revenue credit allocated to the Eastern Intertie segment. *Id.* Table 2.

5.2.3 Eastern Intertie Rate (IE-14)

The IE rate is available to the Colstrip parties to the Montana Intertie Agreement for non-firm transmission service on the Eastern Intertie. The IE-14 rate is calculated by dividing the annual costs of the Eastern Intertie segment, $9.92 million, by the amount of capacity available to the Colstrip parties on the Eastern Intertie, 1,930 MW, then dividing by 8,760 hours (per year), and multiplying by the LLH/HLH factors of 24/16 and 7/5. *Id.* Table 8; *see* Section 4.3. The result is a IE-14 rate of 1.23 mills/kWh.

Under the TGT rate schedule, in each month revenues from any non-firm transactions under the IE-14 and IM-14 rates are deducted from the portion of the total annual costs to be recovered in that month under the TGT rate. The Colstrip parties' portion of the monthly net cost is then allocated to them in accordance with the formula in the TGT rate schedule.

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6. ANCILLARY AND CONTROL AREA SERVICES

BPA provides ancillary and control area services that are separate from transmission services. This Study describes the development of the rates for (1) Scheduling, System Control, and Dispatch Service and (2) Generation Supplied Reactive Service. The Generation Inputs Study, BP-14-E-BPA-05, discusses the development of the rates for other ancillary and control area services BPA provides.

6.1 Scheduling, System Control, and Dispatch Service

All customers purchasing transmission service from BPA are required to purchase SCD service. Customers taking NT and PTP service (including PTP service over the Montana Intertie or the Southern Intertie) purchase SCD separate from transmission service at the rates in the SCD rate schedule. For customers taking IR service, the SCD rate is included in the IR rate. *See* section 4.4. For FPT service, the costs of SCD are included in the development of the FPT rate. *See* section 4.5. Customers taking FPT service do not pay the SCD rate.

The SCD rate schedule includes rates for long-term service; monthly, weekly, and daily service; and hourly service. Like the rate schedules for PTP service, the SCD rate schedule includes "Block 1" and "Block 2" rates for service on a monthly, weekly, or daily basis. One hourly rate applies to all hourly service.

SCD service applies to all transmission service, and the equipment that comprises the Ancillary Services segment supports all transmission service. Transmission

Segmentation Study, BP-14-FS-BPA-06, section 2.7. The calculation of the SCD rate starts with the segmented revenue requirement attributable to Scheduling, System Control, and Dispatch, which averages $133.65 million annually over the rate period. Documentation Table 1. The Study adjusts the SCD costs by applying revenue credits and other adjustments, including the portion of the FPT revenues allocated to SCD. *Id.* Tables 3 and 10; *see* sections 3 and 4.5. The revenue credits and other adjustments reduce the overall SCD costs to an average of $127.92 million annually over the rate period. Documentation Table 10.

As it does with respect to the calculation of rates for NT, PTP, and IR service on the Network, to determine the rates for SCD the Study calculates allocation percentages for SCD sales associated with NT (based on the non-coincident peak load forecast), PTP (including PTP service on the Southern Intertie and Montana Intertie), and IR service based on the ratio of the forecast for each service to the total forecast average annual SCD sales associated all three services, 41,515 MW. Documentation Table 10. The allocation percentages for SCD sales associated with NT, PTP, and IR services are 17.65%, 80.74%, and 1.61%, respectively. *Id.* Multiplying the total adjusted average annual SCD revenue requirement of $127.92 million by the sales percentage for each service yields an allocated cost of $22.58 million for NT service, $103.28 million for PTP service, and $2.06 million for IR service. *Id.* The Study uses these allocated costs to calculate the rates for SCD service associated with NT, PTP, and IR service.

To calculate the SCD rate for NT service, the Study divides the $22.58 million of SCD costs allocated to NT service by the NT billing factor of 6,267 MWs (the average monthly NT coincident peak load forecast for the rate period, not considering the Short Distance Discount). This yields a unit cost of $3,602.63/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $3.60/kW-year. The kW-year unit cost is divided by 12 to yield a monthly SCD for NT service unit cost of $0.300/kW-month. *Id.* The Study sets the SCD rate for NT service equal to this monthly unit cost.

The same methodology is used to calculate the SCD rates for PTP, IR, Southern Intertie, and Montana Intertie service. For the SCD rate for PTP service (including PTP service on the Southern Intertie and Montana Intertie), the PTP share of total SCD sales (80.74%) is multiplied by total average annual SCD revenue requirement of $127.92 million, yielding a total PTP service class cost of $103,277.24 million. This value is divided by forecast average annual PTP sales (Long Term and Short Term combined, and not considering the Short Distance Discount) of 33,518 MWs, yielding a unit cost of $3,081.26/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $3.08/kW-year. This kW-year unit cost is divided by 12 to yield a monthly SCD for PTP service unit cost of $0.257/kW-month. Documentation Table 10.

For the SCD rate for IR service, the IR share of total SCD sales (1.61%) is multiplied by total average annual SCD revenue requirement of $127.92 million, yielding a total IR service class cost of $2,06 million. This value is divided by forecast average annual

IR sales of 669 MWs, yielding a unit cost of $3,081.26/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $3.08/kW-year. This kW-year unit cost is divided by 12 to yield a monthly SCD for IR service unit cost of $0.257/kW-month. Documentation Table 10.

The rates for Block 1 daily and for hourly SCD service include the adjustment for short-term sales that the Study includes for all of the rates for PTP service. Section 4.3 discusses this adjustment. The short-term Block 1 rate of $0.012/kW-day equals the SCD annual unit cost divided by 365 days and multiplied by the LLH/HLH factor of 7/5 (seven days divided by five HLH days). *Id.* The Block 2 rate of $0.008/kW-day equals the SCD annual unit cost divided by 365 days. *Id.* The Study calculates the hourly rate of 0.74 mills/kWh by dividing the annual unit cost by 8,760 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 (24 hours/day divided by 16 HLH/day) and 7/5. *Id.*

6.2 Generation Supplied Reactive Service

The GSR rate is set on a quarterly basis pursuant to a formula in the GSR rate schedule. *See* Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, ACS-14, section II.B. As of October 1, 2007, Transmission Services no longer compensates Power Services for generation inputs associated with providing reactive supply and is not required to pay independent power producers for reactive supply inside the deadband. *See Bonneville Power Admin. v. Puget Sound Energy Inc. et al.*, 120 FERC ¶ 61,211 (2007), *reh'g denied*, 125 FERC ¶ 61,273 (2008). Therefore, no costs exist for GSR inside the deadband. Transmission Services is required to pay generators for reactive supply outside the deadband requested by Transmission Services, pursuant to the generator's FERC-approved rate. Currently, Transmission Services does not expect any costs for GSR outside the deadband during the rate period. Therefore, the GSR rate is expected to be zero for the FY 2014–2015 rate period.

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7. OTHER SERVICES AND PROVISIONS

7.1 Use-of-Facilities Transmission Rate (UFT-14)

Use-of-Facilities Transmission (UFT) service is generally offered in a limited set of situations in which PTP transmission service may not be appropriate. Such situations include, but are not limited to, sales of capacity over a specific set of facilities within a substation (*e.g.*, buswork or a transformer bank) that would not negatively affect power flows on the rest of the transmission system.

The UFT rate schedule includes a formula monthly rate of one-twelfth of the sum of the annual costs of the transmission facilities used by the UFT customer divided by the sum of the transmission demand reserved by the UFT customer. BPA adjusts the costs of operating and maintaining the transmission facilities (the numerator in the UFT formula rate) annually.

The UFT rate schedule also provides for allocating the costs of UFT service between customers that take UFT service over the same transmission facilities, based on the relative use of the facilities. Finally, the UFT rate schedule includes provisions for Ancillary Services, Failure to Comply Penalties, and the Power Factor Penalty Charge.

7.2 Advance Funding Rate (AF-14)

This rate schedule allows BPA to collect the capital and related costs of specific BPA-owned transmission facilities through advance funding by a customer that uses the facilities when advance funding is provided for in an agreement with the customer. Such facilities may include, but are not limited to, interconnection and resource integration facilities and transmission system upgrades, reinforcements, and replacements. The Advance Funding rate provides a mechanism to allow BPA to recover costs and prevent stranded costs for facilities that BPA builds under agreements with particular customers. Following commercial operation of the specified facilities, BPA performs a true-up of estimated costs to actual costs and either bills the customer or issues a refund for the difference between the advance payment and the actual costs.

7.3 Rate Adjustment Due to FERC Order Under Section 212 of the Federal Power Act

This provision is included in the NT, PTP, IS, IM, and ACS rate schedules. These rate schedules, after review by FERC, may be modified to satisfy statutory standards for FERC-ordered transmission service. For customers taking non-FERC-ordered transmission service, any modifications would be effective only prospectively from the date of the final FERC order that grants final approval of the rate schedule for FERC-ordered transmission.

7.4 Delivery Charges

7.4.1 Utility Delivery Charge

The Utility Delivery Charge in GRSP II.A applies to utility customers that take delivery of power over transmission facilities at voltages below 34.5 kV. Utility Delivery customers are customers that serve retail load, such as investor-owned utilities, public utility districts, cooperatives, and municipalities.

Calculating the rate for Utility Delivery service starts with the annual average segmented revenue requirement for the Utility Delivery segment, which is $6.28 million for the rate period. Documentation Table 3. As described in section 3, the Study applies revenue credits and adjustments to this amount to determine the net segmented revenue requirement. After applying the revenue credits and adjustments, the annual average net segmented revenue requirement for the Utility Delivery segment for the rate period is $6.04 million. Documentation Table 3.

The Study determines an annual unit cost for Utility Delivery service by dividing the $6.04 million revenue requirement by the forecast annual average Utility Delivery sales of 195 MW. Documentation Table 9; see Study section 2. This results in an annual unit cost of $30.92 /kW-year and a monthly unit cost of $2.577/kW-month. Documentation Table 9.

Setting the Utility Delivery rate equal to the monthly unit cost would result in a 130 percent increase over the current rate of $1.119/kW-month. To avoid the rate shock that would result from such a large increase in the Utility Delivery rate, the Study limits the increase in the amount of revenue collected through the Utility Delivery rate to 25 percent. This results in $3.28 million in average annual Utility Delivery revenue and a Utility Delivery charge of $1.399/kW-month. Documentation Table 9.

The $3.28 million in average annual revenue expected from the Utility Delivery rate is insufficient to recover the $6.04 million net segmented revenue requirement for the rate period. Documentation Table 9. The $2.76 million in average annual Utility Delivery segment costs that are not recovered through the Utility Delivery Charge are allocated to the other transmission segments and recovered through the rates for those segments. Documentation Table 3; see sections 3.2.2 and 3.2.3.

7.4.2 DSI Delivery Charge

The DSI Delivery Charge applies to DSI customers that take delivery of power over transmission facilities at voltages below 34.5 kV. The DSI Delivery Charge is a Use-of-Facility Charge and is determined under sections III.A and B of the UFT-14 rate schedule. See section 7.1 for explanation of the Use-of-Facility Charge.

7.5 Power Factor Penalty Charge

The Power Factor Penalty Charge is a charge for the reactive power supplied to a generator. Its purpose is to provide an incentive to minimize preventable reactive flows at interconnections with BPA's transmission system. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, GRSP II.C.

BPA calculates the Power Factor Penalty Charge hourly for each point of interconnection or POD between BPA and parties interconnected to BPA's transmission system. If a customer has multiple transmission service agreements (*e.g.*, PTP and IR transmission service) with BPA for service at the same point of interconnection or delivery, BPA will assess only one Power Factor Penalty Charge to that customer for each point of interconnection or delivery. Points of delivery that are served by transfer over another utility's transmission system will not be subject to the Power Factor Penalty Charge unless there are significant BPA Network facilities between the customer's PODs and the intervening utility's system.

BPA bills the customer directly for measured quantities of reactive demand that fall outside a specified deadband. The deadband equals 25 percent of the highest real power demand (based on a 0.97 power factor) at the point of interconnection or POD during the billing month. The Power Factor Penalty Charge applies only to lagging reactive demand during HLH and only to leading reactive demand during LLH. An 11-month ratchet will be applied to the demand charge. There are separate ratchets for leading and lagging reactive demand.

The demand charge for lagging reactive power is based on the installed cost of capacitors, whereas the demand charge for leading reactive power is based on the installed cost of reactors. (Reactors and capacitors are equipment that provide reactive compensation. Reactors compensate for leading power factor and capacitors for lagging power factor.) The rate is the per-unit installed cost of reactors and capacitors and is calculated by dividing the annual cost of the respective facilities by the installed reactive capacity to derive a cost per kVar (a unit of reactive power), then dividing by 12 to yield the monthly cost, and multiplying by two. (The penalty rate is double the monthly cost to reflect the penalty nature of the charge.)

7.6 Failure to Comply Penalty Charge

The Failure to Comply Penalty Charge applies when a party fails to comply with BPA's dispatch, curtailment, redispatch, or load shedding orders necessary to maintain system reliability. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, GRSP II.B. The charge is the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest, measured by the number of kilowatthours a party fails to curtail, redispatch, shed load, or change or limit generation in response to a BPA order. In addition, the party is assessed the costs of alternate measures taken by BPA to ensure that the party's failure to comply does not compromise the reliability of BPA's transmission system and any penalties imposed on BPA for violation of any Reliability Standard(s) caused by the party's failure to comply.

7.7 Unauthorized Increase Charge

For firm transmission service under the PTP, IS, and IM rate schedules, BPA will assess an Unauthorized Increase Charge (UIC) when a customer's transmission usage exceeds its capacity reservations at any Point of Receipt (POR) or POD. GRSP II.G. The UIC rate is the lesser of (i) 100 mills per kilowatthour plus the price cap established by the Commission for spot market sales of energy in the WECC; or (ii) 1000 mills per kilowatthour. If the Commission eliminates the WECC price cap, the rate will be 500 mills per kilowatthour.

For each hour, BPA adds the amounts that exceed capacity reservations for all PODs and amounts for all PORs. The billing factor is the higher of the POR sum or the POD sum. BPA uses hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. For two-way dynamic schedules, actual demands will be the instantaneous peak demand for the hour. The actual demands associated with all other PORs and PODs will be based on 60-minute integrated demands or transmission schedules.

BPA may waive or reduce a UIC that it assesses to a customer based on the criteria in the GRSPs. BPA is not proposing any changes to the UIC waiver or reduction criteria. Because the UIC is a penalty rate and BPA expects customers to limit their usage to the amount of reserved capacity, BPA does not expect to assess this charge during the rate period.

7.8 Reservation Fee

The Reservation Fee, defined in GRSP II.E, is included in the PTP, IS, and IM rate schedules for the FY 2014–2015 rate period. The Reservation Fee applies to PTP transmission customers that, pursuant to OATT Section 17.7, request an extension (deferral) of the Service Commencement Date specified in the Service Agreement. The Reservation Fee is a nonrefundable fee equal to one month's charge for each year or fraction of a year for which the customer extends the service commencement date.

7.9 IR Ratchet Demand

The IR rate schedule includes a Ratchet Demand Relief provision that describes the demonstration the customer must make to obtain a waiver or reduction of a Ratchet Demand. A Ratchet Demand is the maximum demand established during a specified period.

BONNEVILLE POWER ADMINISTRATION
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