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

BP-14 Final Rate Proposal

Generation Inputs Study

BP-14-FS-BPA-05

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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

The Federal Columbia River Power System (FCRPS) hydroelectric projects support BPA's transmission system and are instrumental in maintaining its reliability. In the context of this Generation Inputs Study (Study), FCRPS is used to refer to only generation assets. The uses of the FCRPS to support the transmission system and maintain reliability are generally referred to as generation inputs.

1.1 Purpose of Study

On May 15, 2013, the Administrator issued a Record of Decision (Generation Inputs ROD) on the Settlement Proposal for Generation Inputs and Transmission Ancillary and Control Area Services Rates. Consistent with that decision, this Study provides documentation for the revenue forecasts associated with the Ancillary and Control Area Services rates that were adopted in the Generation Inputs ROD. It also provides documentation for certain generation inputs and inter-business line allocations not addressed by the Settlement Proposal. The revenues that are forecast in this Study are applied in ratesetting as revenue credits in the Power Rates Study, BP-14-FS-BPA-01, section 4.

Generation inputs include energy and balancing reserve capacity from the FCRPS that BPA uses to provide Ancillary and Control Area Services and to maintain the reliability of the transmission system.

1.2 Summary of Study

Section 2 of the Study describes the forecast of balancing reserve capacity needed for the provision of Regulating Reserve, Following Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve, and Dispatchable Energy Resource Balancing Service (DERBS)

Reserve. *See also* Generation Inputs ROD, BP-14-A-01, for the rates applied to those forecast quantities to create the revenue forecast. Section 3 of the Study addresses Operating Reserve (Contingency Reserve) and details the methodology for determining the forecast need. Other generation inputs, including Synchronous Condensing, Generation Dropping, Redispatch Service, and Station Service, are discussed in sections 4, 5, 6, and 8. Segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation Integrated Network and Delivery Facilities costs is discussed in section 7.

A summary of the revenue forecast for supplying these generation inputs is shown in Table 1 of the Study. The Ancillary and Control Area Services rates are shown in Study Table 2.

2. BALANCING RESERVE CAPACITY QUANTITY FORECAST

2.1 Introduction

2.1.1 Purpose of the Balancing Reserve Capacity Quantity Forecast

The Balancing Reserve Capacity Quantity Forecast estimates the amount of balancing reserve capacity needed for BPA to provide certain Ancillary and Control Area Services during the rate period. The forecast described in this section focuses on the balancing reserve capacity needed to provide regulating reserves, following reserves, and imbalance reserves, collectively called balancing services. The quantity of balancing reserve capacity is an essential input for the revenue credit associated with providing the balancing reserve capacity. *See* Table 1.

2.1.2 Overview

As a balancing authority, BPA must maintain load-resource balance in its balancing authority area at all times. All generators within the BPA balancing authority area provide hourly generation schedules to BPA that estimate the average amount of energy they expect to generate in the coming hour. Based on these schedules, BPA estimates the average amount of load to be served in the BPA balancing authority area in the coming hour.

Transmission customers submit hourly transmission schedules, identifying all energy to be transmitted across or within the BPA balancing authority area in the coming hour. BPA uses the transmission schedules to match generation inside the BPA balancing authority area and imports of energy from other balancing authority areas with loads served inside the BPA balancing authority area and exports to other balancing authority areas. The transmission schedules identified with each adjacent balancing authority area are netted to determine interchange schedules. The interchange schedules are netted for the BPA balancing authority area to determine controller totals.

Controller totals are the sum of all energy transactions to and from the BPA balancing authority area. The BPA Automatic Generation Control (AGC) system calculates the deviation between the (i) actual interchange flows and the (ii) controller totals plus dynamic schedules that affect the controller total amount. The AGC system regulates the output of some specified FCRPS generators in the BPA balancing authority area in response to changes in load, system frequency, and other factors to maintain the scheduled system frequency and interchanges with other balancing authority areas. The interchange schedules and controller totals do not change when a generator deviates from its scheduled generation or a load deviates from the average hourly estimate. The balancing authority area uses generation resources, assigned for balancing service and connected to the AGC system, to offset differences between scheduled and actual generation and to maintain within-hour load-resource balance in the balancing authority area.

BPA's AGC system adjusts the generation of projects on automatic control based on the differences between scheduled and actual load and generation. If load increases or generation decreases, the AGC system increases (*incs*) output of balancing resources. If load decreases or generation increases, the AGC system decreases (*decs*) output of balancing resources. The cumulative *inc* and *dec* generation required to maintain load-resource balance within the hour forms the basis for the balancing reserve capacity that BPA must maintain to provide balancing services.

2.2 Existing and Future Generation Projects for the Rate Period

Developing the Balancing Reserve Capacity Quantity Forecast required to provide balancing services during the rate period requires an estimate of the amount of generation that will be online during that period. This estimate includes both the actual generating projects that are online as of the time of the Study based on BPA records and a forecast of the projects that are expected to come online before or during the FY 2014–2015 rate period. Generation Inputs Study Documentation, BP-14-FS-BPA-05A (Documentation), Table 2.1.

The forecast of projects that are expected to come online before or during the FY 2014–2015 rate period is based on a review of the pending requests in BPA's generator interconnection queue, information provided for the requests under BPA's Large Generator Interconnection Procedures (LGIP), and the application of certain criteria. References to "future" or "planned" projects throughout this Study indicate expectations with respect to the interconnection of certain generating projects based on the assessment of the circumstances and information available at the time but are not intended to convey certainty about interconnection of a particular generating project.

To forecast which future generating projects will interconnect and the timing of such interconnections, BPA considers the status of interconnection requests in BPA's interconnection queue in April 2013. For the evaluation of the interconnection queue, the requested interconnection date in each interconnection request is only one of several factors considered to assess a potential interconnection date for a project. Prior to interconnecting, each future project must go through the LGIP study process, under which BPA completes a series of studies prior to offering an interconnection agreement and interconnection date. This can be an extended process, and the timing for the completion can vary substantially; therefore, the evaluation of certain objective factors is necessary to make projections about the status of future projects. Some of the factors include:

1. The status of the interconnection study process. Requests in the earlier stages of the study process are less likely to interconnect in the near term and thus are more likely to be relevant to future rate periods.

2. The status of the environmental review process and interconnection customer permitting process for the request. As a Federal agency, BPA must conduct a review under the National Environmental Policy Act (NEPA) and other Federal laws before deciding whether to interconnect a particular generator. This review can take a substantial amount of time, and BPA typically coordinates its review to coincide with the customer's state or county environmental permitting process. Requests that are not far along in those processes are less likely to interconnect in the FY 2014–2015 rate period.

3. Interconnection and network project additions that affect the time required to complete an interconnection. As studies progress, BPA and the customer develop a more definite plan of service, and the time to construct is better defined. The particular network additions and interconnection facilities required to interconnect the generator and the time it would take to construct those facilities are taken into account.

4. Information received in direct discussions with each developer about its plans (*e.g.,* project scheduling, financing, Federal and state incentives, turbine ordering commitment). A significant factor that affects the interconnection forecast is the date when a customer executes an engineering and procurement agreement, which allows BPA to incorporate the project in BPA's construction program schedule, begin work on the necessary interconnection facilities design, and begin ordering materials and equipment with a long procurement lead time.

5. The execution of an interconnection agreement and commitment by the customer to fund all BPA facilities necessary for the interconnection. A

firm construction program schedule is included in the agreement. Executing an interconnection agreement usually occurs just prior to the construction phase of a project.

Documentation Table 2.1 identifies the amount of installed capacity that BPA forecasts will be online during the FY 2014–2015 rate period for each type of generation accounted for in the Balancing Reserve Capacity Quantity Forecast. The forecast of installed wind capacity is an average of 4,587 MW; installed solar capacity is an average of 23 MW; non-AGC controlled hydroelectric capacity is an average of 2,529 MW; non-Federal thermal capacity is an average of 4,297 MW; and Federal thermal capacity is 1,276 MW.

2.3 Wind Scheduling Commitment and Service Elections

Wind facilities in BPA's balancing authority area made scheduling commitment and service elections in April 2013. In their elections, they chose between participation in Self Supply, Self Supply of the Imbalance portion of their Balancing Reserve Capacity only, committed 30-minute persistence on 15-minute schedules (when and if available), committed 30-minute persistence on 30-minute schedules, committed 30-minute persistence on 60-minute schedules, or uncommitted. The April 2013 elections are shown in Documentation Table 2.2. These elections, along with the installed capacity forecast described in section 2.2 and the rates established in the Generation Inputs ROD, BP-14-A-01, are used to determine the revenue credit to Power Services for provision of balancing reserve capacity. *See* Study Table 1.

2.4 Balancing Reserve Capacity Requirements Methodology

In accordance with the Generation Inputs ROD, BPA will use a 99.5 percent planning standard to determine the total balancing reserve capacity requirement. BP-14-A-01. The methodology for forecasting the balancing reserve capacity requirements uses the following one-minute average datasets: actual balancing authority area load, balancing authority area load forecast, the total hydroelectric generation, the total hydroelectric schedule, the total Federal thermal generation (*i.e.,* Columbia Generating Station or CGS), the total Federal thermal schedule, the total non-Federal thermal generation, the total non-Federal thermal schedule, total solar generation, total solar generation forecast, actual total wind generation, and total wind generation forecast. Using these datasets, the actual load net generation is determined on a minute-by-minute basis. Then the load net generation forecast is determined on a minute-by-minute basis. For purposes of the forecast, the total balancing reserve capacity requirement is the difference between the minute-by-minute variations and the forecast schedules of the load net generation dataset, also known as Station Control Error (SCE). The *inc* and *dec* amounts are calculated for the amounts of wind penetration and load for FY 2014–2015.

Using a percentile distribution, values from the upper and lower 0.25 percent are discarded for each component, leaving 99.5 percent of the values for calculating the capacity requirements of the BPA balancing authority area. The result is a forecast of the balancing reserve capacity that BPA needs to meet its balancing requirements 99.5 percent of the time. Using 99.5 percent of values for the load net generation dataset, the balancing reserve capacity requirement forecast is calculated for the total balancing reserve capacity requirement. The equations below describe these calculations.

Total Reserve Requirement

Total *inc* = p9975(Total SCE)

Total *dec* = p0025(Total SCE)

where p9975 is the 99.75% percentile distribution

p0025 is the 0.25% percentile distribution

Documentation Table 2.2, Columns L and M, identify the amount of total balancing reserve capacity required under the 99.5 percent planning standard.

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3. OPERATING RESERVE REVENUE FORECAST

3.1 Introduction

Operating Reserve is the type of reserve that BPA is required to offer to transmission customers pursuant to Schedules 5 and 6 of BPA's Open Access Transmission Tariff (OATT). Operating Reserve backs up resources in the BPA balancing authority area. Power rates are reimbursed through revenue credits for the costs of providing Operating Reserve. Power Rates Study, BP-14-FS-BPA-01, section 4.3. The reserve that BPA uses for Schedules 5 and 6 of the OATT may be referred to in other contexts as "Contingency Reserve," but for purposes of allocating and assigning costs, BPA refers to such reserve as "Operating Reserve."

In order to calculate the revenue forecast for Operating Reserves, this section describes (1) the applicable Operating Reserve regional reliability standards that apply to the BPA balancing authority area and (2) BPA's methodology for forecasting the amount of Operating Reserve for the rate period.

3.2 Applicable Regional Reliability Standards for Operating Reserve

BPA is obligated under the OATT to offer Operating Reserve, which includes both spinning reserve capacity and non-spinning or supplemental reserve capacity. The OATT requires at least half of the Operating Reserve to be spinning reserve. BPA determines the transmission customer's Spinning and Supplemental Operating Reserve requirement in accordance with applicable North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards.

The current WECC standard requires each balancing authority area to maintain sufficient Operating Reserve to meet the NERC Disturbance Control Standard BAL-STD-002-0.

The amount must be equal to the greater of (1) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency or (2) the sum of 5 percent of the load responsibility served by hydro generation and 7 percent of load responsibility served by thermal generation. At least half of the total requirement must be spinning reserve.

Each NWPP member with variable generation (*i.e.,* wind and solar) in its balancing authority area must maintain Operating Reserve equal to 5 percent of the generation for which the balancing authority has load responsibility.

On March 25, 2009, NERC submitted a petition to the Federal Energy Regulatory Commission (Commission) seeking approval of a WECC-developed regional reliability standard designated as BAL-002-WECC-1, Contingency Reserves, and the concomitant retirement of BAL-STD-002-0. *Version One Regional Reliability Standard for Resource and Demand Balancing*, FERC Docket No. RM09-15, Petition of NERC (Mar. 25, 2009). The proposed WECC standard, BAL-002-WECC-1 (BAL-002), states that the minimum Operating Reserve requirement would be the greater of (1) the most severe single contingency or (2) the sum of 3 percent of load (generation minus station service minus Net Actual Interchange) and 3 percent of net generation (generation minus station service). At least half of the total requirement must be spinning reserve.

On October 21, 2010, the Commission issued a remand for BAL-002 to NERC. *Version One Regional Reliability Standard for Resource and Demand Balancing*, FERC Docket No. RM09-15, Order No. 740, 133 FERC ¶ 61,063 (2010). In addressing concerns of the FERC Order No. 740 remand, BAL-002 was resubmitted and passed in the March 2012 WECC

Operating Committee by a member vote (117 affirmative, 31 negative, 10 abstain, 16 did not vote), and subsequently approved by the WECC Board in June 2012. On April 12, 2013, NERC submitted BAL-002 to FERC for approval. If approved, BAL-002 would become effective the first day of the first calendar quarter that is six months beyond the date it is approved by the Commission.

BPA must base its Operating Reserve forecast on the best information available regarding the WECC standard for Operating Reserve. Based on BPA's estimate of the timing of approval by the Commission, plus the additional six-month requirement for implementation, BPA is assuming that BAL-002 will be implemented at, or within a few months after, the start of the FY 2014–2015 rate period.

3.3 Calculating the Quantity of Operating Reserve Using the Proposed Standard BAL-002-WECC-1

The BPA balancing authority area Operating Reserve obligation under BAL-002 is determined as follows. First, the BPA balancing authority area load is forecast using BPA balancing authority area load in FY 2011 as the base year. The forecast of the loads through FY 2015 is determined through the BPA Agency load forecast, resulting in balancing authority area load growth of 0.87 percent in FY 2013, –0.35 percent in FY 2014, and 2.13 percent in FY 2015. *See* Documentation Table 4.1. Second, BPA balancing authority area generation is forecast based on a ratio of balancing authority area generation to balancing authority area load of approximately 2:1 observed from FY 2010 through FY 2012. The generation forecast is then adjusted for the forecast of two non-Federal thermal generators that are expected to leave the BPA balancing authority area during the rate period. Third, the total BPA balancing authority area Operating Reserve obligation is calculated by summing 3 percent of the forecast load and 3 percent of the forecast generation. The total BPA balancing authority area Operating Reserve obligation under the BAL-002 standard is forecast to be 560.1 MW in FY 2014 and 568.5 MW in FY 2015 (564.3 MW average for FY 2014–2015). Documentation Table 3.1.

Operating Reserve obligation provided by self-supply and third-party supply is based on customer elections for the FY 2014–2015 rate period made on May 1, 2013. To adjust that total for the FY 2014–2015 rate period, two adjustments are made. First, the stated election is adjusted to an expected provision basis. The hourly self-supply and third-party provision for FY 2012 is analyzed using a cumulative probability function. Based on the historical data, BPA expects that approximately 80 percent of the election amount will be self-supplied. Second, because the proposed WECC standard is based on 3 percent of load and 3 percent of generation, an additional step is needed to adjust the reserve obligation for third-party and self-suppliers. This second adjustment accounts for the change in the Operating Reserve multiplier from 5.2 percent (the current Operating Reserve multiplier for BPA Federal generation mix based on the weighted average of 7 percent for thermal resources and 5 percent for hydro and wind resources) to 6 percent (3 percent of generation and 3 percent of load) pursuant to the proposed change in the WECC standard. If the third-party and self-suppliers have both load and generation in the BPA balancing authority area, the multiplier is adjusted from 5.2 percent to 6 percent. If either load or generation is outside the BPA balancing authority area, the multiplier is adjusted from 5.2 percent to 3 percent. The FY 2014–2015 election amount of third-party supply and self-supply is then multiplied by 80 percent (Eighty per cent is the FY 2012–2013 average use of third-party supply and self-supply as compared to the election for that rate period.), which results in a FY 2014–2015 forecast of 108.5 MW out of BPA's total reserve obligation that will be third-party and self-supplied.

The difference between the total BPA balancing authority area Operating Reserve obligation and the amount provided by self-supply and third-party supply yields BPA's Operating Reserve obligation. Assuming Commission approval of the proposed BAL-002 standard, the Power Services Operating Reserve obligation would be 451.6 MW in FY 2014 and 460.0 MW in FY 2015 (455.8 MW average for FY 2014–2015). Documentation Table 3.2. Shaped monthly Operating Reserve amounts for FY 2014–2015, shown in Documentation Table 3.3, are based on the monthly FY 2005–2011 percentage of BPA balancing authority area loads and BPA balancing authority area generation.

3.4 Operating Reserve Revenue Forecast

The Spinning and Supplemental Operating Reserve rates were set in the Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates, BP-14-A-01, Attachment 1. Applying the settled rates to the forecast quantities yields a revenue forecast of $21,680,947 for Operating Reserve – Spinning, and $19,864,220 for Operating Reserve – Supplemental. Study Table 1, lines 14-15.

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4. SYNCHRONOUS CONDENSING

4.1 Introduction

A synchronous condenser is essentially a motor with a control system that enables the unit to regulate voltage. These machines dynamically absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system.

Some FCRPS generators operate in synchronous condenser or "condense" mode for voltage control and for other purposes (*e.g.,* to accommodate operational constraints associated with taking a unit offline). Generators operating in condense mode provide the same voltage control function as they do when generating real power. As with any motor, a unit operating in condense mode consumes real energy. Generators operating in condense mode in the FCRPS consume energy supplied by other units in the FCRPS.

4.2 Synchronous Condenser Costs

Synchronous condensing costs are allocated to Transmission Services and recovered through transmission rates. Synchronous condensing costs include the cost of (1) energy consumed by FCRPS generators while operating in condense mode for voltage control; and (2) investments in plant modifications at the John Day and The Dalles projects necessary to provide synchronous condensing that were not part of the original design. This investment was made because adding voltage support from these plants could best serve line loading concerns related to the Southern Intertie. Because this investment and the operation of these synchronous condensers are primarily to serve Southern Intertie needs, these costs are separated from other synchronous condensers' costs, which primarily serve the BPA Network.

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $287,000 per year. Documentation, Table 4.2, line 9; Power Revenue Requirement Study Documentation, BP-14-FS-BPA-02A, Tables 2E and 2F. These costs are the annual capital-related costs in the generation revenue requirement associated with the investment that Power Services made in the plants at the request of Transmission Services to enable synchronous condensing capability.

For the costs associated with the energy used in condense mode operations, the amount of forecast energy is priced at an average annual market price, as described below.

4.3 General Methodology to Determine Energy Consumption

For the FY 2014–2015 rate period, the FCRPS generators capable of operating in condense mode are identified, and the number of hours that the generators would operate in condense mode for voltage control is forecast. The forecast is derived from historical synchronous condenser operations, based on an average of the most recent three years of data available, which are fiscal years 2007, 2008, and 2009. The average number of hours of use during these three years is multiplied by the fixed hourly energy consumption for the generators to determine the amount of energy consumed. The fixed hourly energy consumption is the motoring power consumption of the specific generator units when they are operated in condense mode. Documentation Table 4.1. Finally, the market price forecast shown in Table 4.1 is applied to the amount of energy consumed to calculate the cost of synchronous condensing. The methodology for assigning historical synchronous condenser operations to the voltage control function and calculating the associated energy use for each of the FCRPS projects capable of operating in condense mode is described below.

4.3.1 Grand Coulee Project

Six generators (Units 19–24) at Grand Coulee are capable of operating as synchronous condensers, although only three are typically operated in condense mode. The Study forecasts the number of hours that the Grand Coulee units will operate in condense mode based on historical condenser operations for the three-year historical period. The transmission system typically needs additional voltage control from Grand Coulee during nighttime hours (generally 10 p.m. to 6 a.m.) when the lightly loaded transmission system generates excess reactive power and causes voltage on the system to be high. If units online generating real power are insufficient to provide the needed voltage control during the night, then units in condense mode are assigned to voltage control.

For the forecast, the total measured reactive demand that the transmission system placed on the six units during the nighttime hours is determined, based on reactive meter readings for the historical three-year period. The total measured reactive demand represents the total reactive support (*i.e.*, megavolt amperes reactive) provided by the six units, regardless of whether the units are condensing or generating real power.

For each hour, the total measured reactive demand is compared to the reactive capability of the units online generating real power plus, if not operating, the reactive capability of the shunt reactor (which absorbs reactive power and reduces voltage on the transmission system). If the reactive capability of online units and the shunt reactor is less than the total measured reactive demand for the hour, one or more units operating in condense mode are allocated to voltage control for that hour. If a condensing unit is allocated to voltage control for a single nighttime hour, the condensing operation of that unit is allocated to voltage control for the entire nighttime period to reflect the fact that, in practice, a unit would not be started and stopped on an hourly basis. Condensing units are allocated to voltage control in whole increments until the total measured reactive demand is met or exceeded.

The number of condensing hours for the three-year historical period is averaged, and energy consumption is determined by multiplying the average annual condensing hours by the fixed hourly energy consumption of the generators. The forecast of total energy consumed by the Grand Coulee generators operating in synchronous condense mode for voltage control is 27,368 MWh. Documentation Table 4.1, line 4.

4.3.2 John Day, The Dalles, and Dworshak Projects

John Day has four generators (Units 11–14), The Dalles has five generators (Units 15–20), and Dworshak has three generators (Units 1–3) capable of operating as synchronous condensers. These three projects condense only when requested by Transmission Services, so all hours in condense mode are for voltage control. The number of condensing hours using meter data for the three-year historical period is averaged, and energy consumption is calculated by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the applicable hydro units. The forecast of total energy consumed by the generators operating in condense mode for voltage control is 15,091 MWh for John Day and The Dalles (*id.* line 3) and 884 MWh for Dworshak. *Id.* lines 5 and 6.

4.3.3 Palisades Project

Palisades has four generators (Units 1–4) that are capable of synchronous condensing. Units are operated in condense mode pursuant to standing instructions from Transmission Services based on operational studies, so all hours in condense mode are for voltage control. The number of condensing hours using meter data for the three-year historical period is averaged. Energy consumption is determined by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the project. The forecast of energy consumption by the Palisades generators operating in condense mode for voltage control is 1,054 MWh. *Id.* line 7.

4.3.4 Willamette River Projects

The Willamette River projects have seven generators capable of condensing, which include units in Detroit (Units 1–2), Green Peter (Units 1–2), and Lookout Point (Units 1–3). Historically, these units have been operated at times in condense mode. However, BPA studies indicate that condensing is not required for voltage support except under rare conditions. Therefore, the energy for condensing operation for voltage control is forecast to be zero for the Willamette River projects. *Id.* lines 8-10.

4.3.5 Hungry Horse Project

Hungry Horse has four generators (Units 1–4) capable of condensing. Although capable of condensing, Hungry Horse was not requested to operate in condense mode during the three-year historical period. Therefore, the energy consumption for the Hungry Horse generators is forecast to be zero. *Id.* line 11.

4.4 Costs Allocated to Transmission Services

The investments in plant modifications at John Day and The Dalles result in an average cost of $288,000 per year. Documentation Table 4.2; Power Revenue Requirement Study Documentation, BP-14-FS-BPA-02A, Tables 2E and 2F.

The energy forecast to be consumed by FCRPS generators operating in condense mode totals 44,397 MWh. Documentation Table 4.1. The energy consumed for condensing operation is priced at the market price forecast as shown in the Power Risk and Market Price Study, BP-14-FS-BPA-04, section 2.4. Applying the market price forecast of $28.85 per MWh to the energy consumed results in a total cost of $1,280,853 per year. Documentation Table 4.1, line 13.

Total synchronous condensing cost allocated to Transmission Services is $1,568,000 per year. Documentation Table 4.3, line 5. This amount is made up of $435,000 per year in energy costs (*id.* line 2), $288,000 per year in plant investments for the Southern Intertie (*id.* line 1), and $845,000 in energy costs for the Network. *Id.* line 4.

5. GENERATION DROPPING

5.1 Introduction

This section describes the method for allocating costs of Generation Dropping, including identifying the assumptions used in the methodology and establishing the generation input cost allocation that is applied to determine the annual revenue forecast for generation inputs.

5.2 Generation Dropping

The BPA transmission system is interconnected with several other transmission systems. To maximize the transmission capacity of these interconnections while maintaining reliability standards, Remedial Action Schemes (RAS) are developed for the transmission grids. These schemes automatically make changes to the system when a contingency occurs to maintain loadings and voltages within acceptable levels. Under one of these schemes, Power Services is requested by Transmission Services to instantaneously drop (disconnect from the system) large increments of generation (at least 600 MW). To satisfy this requirement, the generation must be dropped virtually instantaneously from a certain region of the transmission grid. Under the current configuration of the transmission grid and the individual generating plant controls, Power Services can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity).

5.3 Forecast Amount of Generation Dropping

Historically, large generating units at Grand Coulee have been dropped 18 times over the last 17 years (1996–2012). Therefore, the estimate of "large generating units dropped" is an average of approximately one drop per year.

5.4 General Methodology

The valuation approach considers two factors. First, the desired Generation Dropping Service or "forced outage duty" causes additional wear and tear on equipment that will decrease the life and increase the maintenance of the unit. For each major component that is affected by this service, Documentation Table 5.1 shows the cost associated with equipment deterioration, replacement, and overhaul, and the cost associated with routine operation and maintenance.

Power Services previously contracted with Harza Engineering Company to work with Reclamation and COE (which own and operate the Columbia River system plants) to evaluate the costs of providing this "generation drop" service. The evaluation estimated the cost incurred by a typical Reclamation or COE generating unit. These cost estimates are applied to a generating unit at the Grand Coulee Third Powerhouse. The costs in the original engineering study are updated using the Handy-Whitman Index to reflect price escalation of equipment and labor costs.

Second, lost revenues resulting from the outages required during replacement or overhaul of the equipment are computed. The market price forecast is applied to the energy amounts to determine the costs. Power Risk and Market Price Study, BP-14-FS-BPA-04, section 2.4. Documentation Table 5.1, columns H–K, shows the calculation of this lost revenue.

5.5 Generation Dropping Cost

Historical data for the Grand Coulee Third Powerhouse generating units and statistical data for other hydroelectric units provide capital cost, operation and maintenance costs, and frequency of operation information for the generation dropping analysis. Stresses on the equipment during "forced outage duty" versus stresses during "normal operation" are compared. Through the application of this data, the capital and operation and maintenance costs for the generation drop service are developed. The impacts are converted into a percentage change in equipment life for each operation. Finally, the estimated costs and lost revenue for the most likely type of overhaul or replacement that would need to be made are evaluated for a reduced life expectancy of the equipment. Documentation Table 5.1, column B, shows the percentage reductions in life expectancies per generation drop. These percentages are also used to determine the incremental routine O&M cost.

In addition to capital and operation and maintenance costs, the revenue lost during outages for the overhaul or replacement of equipment is significant for the large generating units with a capacity exceeding 600 MW. Although some outages for routine maintenance could be scheduled to avoid large revenue losses, other outages cannot be scheduled to avoid lost revenues. Thus, such lost revenues are calculated based on the forecast market price averaged over the rate period, FY 2014–2015. It is assumed that these outages are unpredictable or longer than scheduled, and cannot be scheduled to avoid a loss in total project generation. Documentation Table 5.1, columns H–K, shows the calculation of the lost revenue.

5.6 Equipment Deterioration, Replacement, or Overhaul

The effect of additional deterioration because of Generation Dropping is a reduced period of time between major maintenance activities, such as major overhauls or replacements. For purposes of this analysis, a "major overhaul" is defined as a maintenance activity for which at least partial disassembly of the affected equipment is required. The analysis focuses on evaluating the costs of additional, short-term deterioration of specific components or items for which statistical data are readily available. The costs of a major overhaul are derived from estimates or similar work performed in the past. The percentage life reductions are determined using industry standards or actual project records. For example, turbine overhaul is a major maintenance effort that will be increased in frequency as a result of more frequent severe duty cycles.

5.7 Costs to be Allocated to Transmission Services

The factors described above are analyzed for their application on a single generating unit at the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall cost associated with each generation drop.

From the analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units is calculated to be $333,061. Documentation Table 5.1, line 6. Because the estimate of large generating units dropped is an average of one drop per year, the annual cost is $333,061. This cost is assigned to Transmission Services for recovery in transmission rates. The rate period annual average cost for Generation Dropping is a revenue credit to the power rates. Power Rates Study, BP-14-FS-BPA-01, section 4.3.

6. REDISPATCH

6.1 Introduction

Under Open Access Transmission Tariff (OATT) Attachment M, Transmission Services initiates redispatch of Federal resources as part of congestion management efforts. Generally, redispatch results in decrementing *(dec)* resources that can effectively relieve flowgates that are at or near Operating Transfer Capability (OTC) limits and incrementing *(inc)* other resources to maintain service to loads. Transmission Services is paid for the decrementing of resources and pays for the incrementing of resources. This concept is intended to keep the incrementing and decrementing resource whole financially.

In the case of a decrementing resource, the resource owner avoids certain costs associated with generation, such as fuel costs and operation and maintenance costs, and decrementing the resource also reduces the risk that a curtailment may be necessary to relieve the congestion. As a result, the owner of the decrementing resource pays Transmission Services the equivalent of its avoided costs and reduces the risk of curtailments.

In the case of an incrementing resource, the resource generates energy that it could have otherwise sold. To keep the incrementing resource whole financially, Transmission Services pays the resource owner for the value of that generation. In practice, under OATT Attachment M, Power Services is the provider of both the *inc* and the *dec* resource. This typically results in a net payment to Power Services for each redispatch event. In this document the term "revenue" or "amount" refers to the net revenue associated with the Power Services *inc* and *dec* redispatch activity.

There are three levels of redispatch under OATT Attachment M that Transmission Services can request from Power Services to relieve flowgate congestion: Discretionary Redispatch, NT Firm Redispatch, and Emergency Redispatch. Power Services may provide redispatch under Attachment M through redispatch of Federal generation, through purchases and/or sales of energy, or through transmission purchases. The purposes of each of these types of redispatch are discussed further below. The actual revenue Power Services receives from Transmission Services for providing redispatch under Attachment M is calculated based on one of two sources, depending on how the redispatch is provided, either (1) based on market prices for incrementing and decrementing Federal generation at the time the redispatch is provided, for redispatch provided from Federal generation, or (2) based on the actual cost to Power Services of purchasing and/or selling power or purchasing transmission, for redispatch provided by purchases and/or sales of energy or purchases of transmission.

This Study forecasts revenues Power Services expects to receive from Transmission Services for the provision of redispatch under Attachment M. The revenue forecast for Power Services providing redispatch for FY 2014–2015 is developed by identifying the costs from Power Services providing redispatch in FY 2010–2011, the most recent rate period for which BPA has actual data, and comparing this amount to the forecast for the same period. The forecast is adjusted up or down based on this comparison and on the variables that drive the costs of redispatch. The forecast may be adjusted upward to reflect potential increases due to increased uncertainty or anticipated increases in market prices; or it may be adjusted downward to reflect unusual redispatch events that are not expected to recur, increased constraints on Power Services' ability to provide redispatch, or anticipated decreases in market prices.

6.2 Discretionary Redispatch

Under OATT Attachment M, Transmission Services may request bids for Discretionary Redispatch from Federal resources to *inc* and *dec* generation prior to curtailment of any transmission schedules. Power Services may respond to requests for Discretionary Redispatch by offering, at each generating project, either no Discretionary Redispatch or any amount of Discretionary Redispatch up to the amount requested.

For FY 2010 and FY 2011, Transmission Services forecast payments to Power Services for Discretionary Redispatch of $175,000 per year. Actual Power Services revenues from the Discretionary Redispatch that Power Services provided to Transmission Services totaled $46,439 in FY 2010 and $11,355 in FY 2011. Documentation Table 6.1, lines 28-29. Documentation Table 6.1 provides the actual monthly Discretionary Redispatch revenues and other details for FY 2010 and FY 2011.

As described above, the actual Power Services revenues for FY 2010 and FY 2011 were considerably lower than the $175,000 per year forecast for the FY 2010–2011 rate period. Power Services' provision of Discretionary Redispatch and the resulting revenues have been declining over time as the FCRPS becomes more constrained. Power Services' provision of Discretionary Redispatch and associated actual revenues in FY 2011 were much lower than forecast costs due in part to an extremely high water year. High water conditions limit flexibility on the FCRPS and thus limit Power Services' ability to provide redispatch of Federal generation.

The forecast for FY 2014 and FY 2015 Discretionary Redispatch is $50,000 per year. This is a reduction from previous years' forecasts and is based on the lower-than-forecast actual revenues in FY 2010 and FY 2011 and increasing constraints on Power Services' ability to provide Discretionary Redispatch on a monthly and seasonal basis. The forecast amount for FY 2014 and FY 2015 is greater than actual average revenues in previous years to reflect the unpredictable nature of transmission congestion and the need for Discretionary Redispatch, and the risk inherent in forecasting Discretionary Redispatch costs.

6.3 NT Firm Redispatch

NT Firm Redispatch is provided under OATT Attachment M. Transmission Services requests NT Firm Redispatch from Power Services to maintain firm NT schedules after all non-firm Point-to-Point and secondary NT schedules are curtailed in a sequence consistent with NERC curtailment priority. Power Services must provide NT Firm Redispatch when requested by Transmission Services to the extent that it can do so without violating non-power constraints.

For FY 2010–2011, Transmission Services forecast payments to Power Services for NT Firm Redispatch of $225,000 per year. Actual revenues to Power Services from NT Firm Redispatch provided to Transmission Services totaled $49,261 in FY 2010 and $470,500 in FY 2011 (averaging $259,881 per year). Documentation Table 6.2, lines 26-27. This revenue represents payments from Transmission Services to Power Services associated with NT Firm Redispatch provided through transmission purchases only. There were no Power Services revenues associated with Power Services providing NT Firm Redispatch through the redispatch of Federal generation or through power purchases or sales over this time period. Documentation Table 6.2 provides, for FY 2010 and FY 2011, the actual monthly NT Firm Redispatch revenues, the megawatthours redispatched, dollars per megawatthour, and the constrained path.

Given the increase in the need for NT Firm Redispatch in FY 2011, which is expected to continue, the resulting higher-than-forecast average annual revenues in the FY 2010–2011 rate period, and the variability in transmission and power prices on a monthly and seasonal basis, the forecast for NT Firm Redispatch in FY 2014–2015 is $350,000 per year.

6.4 Emergency Redispatch

Emergency Redispatch is provided under OATT Attachment M. Transmission Services requests Emergency Redispatch from Power Services when Transmission Services declares a System Emergency as defined by NERC. Power Services must provide Emergency Redispatch when requested by Transmission Services even if Power Services may violate non-power constraints.

The forecast of costs from the provision of Emergency Redispatch by Power Services to Transmission Services was $0 for the FY 2010–2011 and FY 2012–2013 rate periods. Actual revenues from Emergency Redispatch provided by Power Services to Transmission Services for FY 2010 totaled $1,510, resulting from one Emergency Redispatch event. No Emergency Redispatch was provided in FY 2011.

Due to the unlikely nature of Emergency Redispatch and the low actual revenues of Emergency Redispatch for FY 2010 and FY 2011, the cost of Emergency Redispatch is forecast to be $0 for FY 2014–2015.

6.5 Revenue Forecast for Attachment M Redispatch Service

Based on the analysis above, a total of $400,000 per year is forecast for FY 2014–2015 for redispatch services provided by Power Services to Transmission Services under OATT Attachment M.

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7. SEGMENTATION OF U.S. ARMY CORPS OF ENGINEERS AND U.S. BUREAU OF RECLAMATION TRANSMISSION FACILITIES

7.1 Introduction

The U.S. Army Corps of Engineers (COE) and U.S. Bureau of Reclamation (Reclamation) own transmission facilities associated with their respective generating projects within the FCRPS. All COE and Reclamation costs are assigned to the generation function in the Power Revenue Requirement Study, BP-14-FS-BPA-02. Therefore, this study identifies COE and Reclamation transmission-related investment so that the proper portion of the annual cost of these transmission facilities may be assigned to Transmission Services. The annual cost of these transmission facilities includes operations and maintenance (O&M) expenses, depreciation, interest expense, and Minimum Required Net Revenue (MRNR).

The COE and Reclamation transmission-related investment is associated with three Federal Columbia River Transmission System (FCRTS) segments: (1) Generation Integration, (2) Integrated Network, and (3) Utility Delivery. The Generation Integration investment is assigned to Power Services to be recovered through power rates. The average annual cost of the Network and Utility Delivery investments over the rate period is allocated to Transmission Services, with an offsetting revenue credit to the Power Services revenue requirement. The definitions of these segments are consistent with the definitions used in the Transmission Segmentation Study, BP-14-FS-BPA-06, section 2. The relevant segment definitions and cost treatment are described below.

7.2 Generation Integration

Generation Integration facilities connect Federal generation to the BPA Network. This segment includes generator step-up transformers (GSUs) and the substation terminals and lines that integrate the Federal generation into the network. The COE and Reclamation Generation Integration costs are functionalized to the generation function.

7.3 Integrated Network

Integrated Network facilities provide for bulk transmission of electric power within the Pacific Northwest and operate at voltages of 34.5 kilovolts (kV) and above. This Study identifies the COE and Reclamation transmission costs that are associated with Network facilities and allocates these costs to Transmission Services.

7.4 Utility Delivery

Utility Delivery facilities deliver power to BPA utility customers at voltages below 34.5 kV. The COE and Reclamation transmission costs that are associated with Utility Delivery facilities are allocated to Transmission Services.

7.5 COE Facilities

The transmission facilities owned by the COE are primarily GSUs and associated equipment at the projects. These facilities are all associated with Generation Integration, which is functionalized to the generation function. There is one exception at the Bonneville Project. At Bonneville Powerhouse No. 1, the COE owns the switching equipment on the dam that performs both Network and Generation Integration functions. This switching equipment is segmented between Network and Generation Integration as described in Documentation Table 7.1.

7.6 Reclamation Facilities

Reclamation owns the lines and switchyards in the substations at its plants within the FCRPS. The primary function of these facilities is to connect the generators to the Network, but at some substations there are facilities that perform Network and Utility Delivery functions. The Documentation shows the information used to assign the lines and substation investment at each Reclamation project to the appropriate segment. Documentation Tables 7.2 and 7.3 describe the Columbia Basin project (Grand Coulee), and Table 7.5 describes the other Reclamation projects: the Hungry Horse Project, the Roza and Kennewick Divisions of the Yakima Project, the Rogue River (Green Springs) Project, the Minidoka and Palisades Divisions of the Minidoka-Palisades Project, and the Boise Project (Anderson Ranch and Black Canyon).

The available Reclamation investment data does not disaggregate costs to the equipment level. Therefore, to develop investment by segment(s), typical costs are used as a proxy for major pieces of equipment. Documentation Tables 7.4 and 7.5. The proxy investment by segment is divided by the total proxy investment for each switchyard or facility to develop a percentage for each segment. These percentages are then multiplied by the actual total switchyard or facility investment to estimate the actual investment for each segment. *Id.* The segment percentage is multiplied by the total transmission investment for each facility to determine the segment investment. Documentation Tables 7.3 and 7.5.

The investment related to the land associated with the Reclamation switchyard equipment is included in the total investment. As shown on Reclamation financial statements, the total investment related to the land associated with the switchyards at the Roza Division of the Yakima Project, the Minidoka Division of the Minidoka-Palisades Project, and the Boise Project totals $10,458, or about 0.06 percent of the combined $18,937,411 investment of these projects. Documentation Table 7.5.

7.6.1 Columbia Basin Transmission Investment

The Columbia Basin project includes generation equipment and associated switchyard equipment. The Reclamation transmission facilities start at the generator side (low side) of the step-up transformer and include the step-up transformers but not the powerhouse switching equipment. The Columbia Basin project investment also includes the 115/12.5 kV facilities at the Coulee Left Switchyard, which are used for station service and deliver power at 12.5 kV to the Town of Coulee Dam, Nespelem Valley Electric Cooperative at Lone Pine, and Grant PUD. Documentation Tables 7.3 and 7.4. Because these facilities serve both Generation Integration and Utility Delivery functions, the investment at these facilities is segmented accordingly.

In calculating the investment for the Columbia Basin project, interest during construction (IDC) and other general costs are allocated based on investment. The IDC allocated to each segment is based on the IDC for the entire project divided by the total project investment, or an interest rate of 11.6 percent, using FY 2011 data. Documentation Table 7.3, line 5. The investment in the Columbia Basin project does not include construction work in progress.

The inclusion of land costs increases the Columbia Basin investment by $70,623, or 0.03 percent of the total investment. *Id.* line 12. In accordance with Reclamation practice, IDC is not applied to land associated with Columbia Basin transmission costs.

The Generation Integration segment comprises 67.8 percent of the transmission investment in the Columbia Basin project; the Integrated Network segment comprises 31.1 percent; and the Utility Delivery segment comprises 1.1 percent. *Id.* line 31.

7.7 Annual Cost of the COE and Reclamation Facilities allocated to Transmission Services

The investment for COE and Reclamation transmission facilities totals $200.9 million for Generation Integration, $77.5 million for Integrated Network, and $2.4 million for Utility Delivery. Documentation Table 7.6, line 7. The proportion of the investment associated with Integrated Network and Utility Delivery facilities compared to the total hydro system investment is used to develop the proportion of the total hydro system costs allocated to Transmission Services.

For each facility, the annual forecast of total hydro system O&M expense is multiplied by the ratio of the facility's transmission investment (Integrated Network plus Utility Delivery) to the total hydro system investment to determine the amount of the total hydro system O&M expense that is allocated to Transmission Services. Power Revenue Requirement Study Documentation, BP-14-FS-BPA-02A, Tables 2G and 2H. The O&M expense allocated to Transmission Services at each facility is then further allocated between the Integrated Network and Utility Delivery segments according to the allocated investment in each segment for the facility. The segmented O&M costs across all the facilities are added to determine the annual total O&M costs allocated to Transmission Services.

The depreciation expense for each facility is calculated based on the gross transmission investment in the facility and the appropriate depreciation rates. *Id.* The depreciation at each facility is allocated between the Integrated Network and Utility Delivery segments according to the allocated investment in each segment for the facility. The segmented depreciation costs across all the facilities are added to determine the annual total depreciation costs allocated to Transmission Services.

A portion of the general costs to be recovered from all power rates is included in the transmission costs associated with the COE and Reclamation facilities, because they are part of the FCRPS. This includes both the hydro system net interest expense and hydro system MRNR. *Id*. These costs are multiplied by the ratio of the COE and Reclamation transmission net plant investment to the hydro system net plant investment to calculate the portion of the hydro system interest expense and MRNR allocated to Transmission Services. The costs allocated to Transmission Services are further allocated to the Integrated Network and Utility Delivery segments according to the investment allocated to each segment from all COE and Reclamation facilities.

Adding the costs from each category results in a total annual cost allocated to Transmission Services of $7.699 million for FY 2014 and $7.500 million for FY 2015. *Id*. The power revenue requirement is reduced by these amounts, and the transmission revenue requirement is increased by these amounts, for each respective year of the rate period.

8. STATION SERVICE

8.1 Introduction

Station service refers to real power that Transmission Services takes directly off the BPA power system for use at substations and other locations, such as facilities located on BPA's Ross Complex and Big Eddy/Celilo Complex. For purposes of this Study, station service does not include power that BPA purchases from another utility or that is supplied by another utility for station service purposes. Because there are locations on the system where BPA does not have meters to measure station service use, the amount of energy use at BPA substations and other facilities is estimated. The annual average forecast market price from the Power Risk and Market Price Study, BP-14-FS-BPA-04, section 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use. This section describes the station service energy use and determines the costs that are allocated to Transmission Services for station service energy use.

8.2 Overview of Methodology

The station service costing methodology consists of the following steps. First, the amount of installed transformation is established, measured in kilovolt amperes (kVA) at all BPA substations served directly by the BPA power system. Second, the historical monthly average station service energy use is determined for substations for which load data exists. Third, an average load factor is derived based on the ratio of installed station service transformation and energy use for those substations for which load data exists. Fourth, the station service energy use for all facilities other than the Ross and Big Eddy/Celilo complexes is estimated by applying the average load factor to the total installed station service transformer capacity. This energy use is then added to the historical use for the Ross and Big Eddy/Celilo complexes to estimate total average monthly energy use. The monthly amount is multiplied by 12 to yield an annual average estimated total energy use for all substations, which is then adjusted for transmission losses by applying the BPA network loss factor, 1.9 percent. The annual average forecast market price from the Power Risk and Market Price Study, BP-14-FS-BPA-04, section 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use.

8.3 Assessment of Installed Transformation

The methodology begins by identifying the amount of installed transformation for all BPA substations. Installed transformation transforms power to a lower voltage to supply power to the buildings and equipment at the substations. The total installed transformation is 46,214 kVA. Documentation Table 8.2, line 6. Of this amount, the total amount of installed transformation at BPA substations for which load data exists is 15,456 kVA. Documentation Table 8.1, line 41.

8.4 Assessment of Station Service Energy Use

The historical average monthly use for the Ross Complex is 1,749,300 kWh and for the Big Eddy/Celilo Complex is 1,822,937 kWh, for a total of 3,572,237 kWh. Documentation Table 8.2, lines 4-5.

The total historical average monthly use for other BPA locations for which load data exists is 1,066,446 kWh. Documentation Table 8.1, line 41. Because not all use is metered, the total average monthly use for BPA substations is estimated based on the historical average monthly use multiplied by the average load factor. Documentation Table 8.2, lines 1-3.

8.5 Calculation of Average Load Factor

The average monthly load factor is calculated by dividing the total historical monthly use for BPA substations for which load data is available by the total installed station service transformation for these BPA substations. This yields an average 9.45 percent load factor. Documentation Table 8.1, line 41.

8.6 Calculating the Total Quantity of Station Service

The total installed transformation is multiplied by the average calculated load factor to yield the calculated historical average monthly use for all facilities other than the Ross and Big Eddy/Celilo complexes. Documentation Table 8.2, lines 1-3. The historical station service energy use for the Ross Complex and Big Eddy/Celilo Complex is then added to the calculated amount of energy use at all other BPA substations. *Id.* lines 4-5. The total quantity of station service average use that Power Services supplies directly to BPA substations and other facilities is then adjusted for transmission losses by multiplying the average use by the BPA Transmission Network loss factor of 1.9 percent. BPA Open Access Transmission Tariff Schedule 11. The adjusted quantity of station service average use supplied to BPA substations and other facilities after adding in network losses is estimated to be 82,665,068 kWh per year. *Id.* line 6.

8.7 Determining Costs to Allocate to Station Service

The annual average forecast market price (Power Risk and Market Price Study, BP-14-FS-BPA-04, section 2.4) applied to the estimated annual quantity of station service energy yields the costs per year to be allocated to station service. The rate period annual average cost for station service is $2,384,885. Documentation Table 8.2.

The rate period annual average cost for station service is a revenue credit to the power rates. Power Rates Study, BP-14-FS-BPA-01, section 4.3.

These costs are assigned to the Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Generation Integration transmission segments based on the allocation of three-year average Operations & Maintenance segmentation. Transmission Revenue Requirement Study, BP-14-FS-BPA-08.

TABLES

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Table 1 Power Services' Generation Inputs Revenue Forecast for FY 2014-2015					
	A	B	C	D	E
	Generation Inputs	Rate or Cost	Unit	Annual Average for FY 2014-2015 Forecast Quantity	Annual Average for FY 2014-2015 Revenue Forecast
1	Regulating Reserve	**0.12**	**mills/kWh/month**	**5,763**	$ 6,058,066
2	Variable Energy Resource Balancing Service Reserve - 30/60 Committed Scheduling	$ 1.20	$/kW/month	1,067	$ 15,364,800
3	Variable Energy Resource Balancing Service Reserve - 40/15 Committed Scheduling	$ 0.94	$/kW/month	-	$ -
4	Variable Energy Resource Balancing Service Reserve - 30/30 Committed Scheduling	$ 0.87	$/kW/month	25	$ 261,000
5	Variable Energy Resource Balancing Service Reserve - 30/15 Committed Scheduling	$ 0.73	$/kW/month	-	$ -
6	Variable Energy Resource Balancing Service Reserve - Uncommitted Scheduling	$ 1.48	$/kW/month	2,104	$ 37,367,040
7	Variable Energy Resource Balancing Service Reserve - Self-Supply of Generation Imbalance	$ 0.40	$/kW/month	1,391	$ 6,676,800
8	Adjustment for VERBS Mid-Rate Period Elections Forecast				$ (3,649,800)
9	Variable Energy Resource Balancing Service for Solar	$ 0.21	$/kW/month	23	$ 57,960
10	Dispatchable Energy Resource Balancing Service Reserve *inc*	18.15	mills/kW/month	150,317	$ 2,728,254
11	Dispatchable Energy Resource Balancing Service Reserve *dec*	3.94	mills/kW/month	98,410	$ 387,735
12	Dispatchable Energy Resource Balancing Service Reserve Total				**$ 3,115,989**
13	Adjustment for Settlement for Generation Inputs and Transmission Ancillary and Control Area Service Rates				$ (3,769,249)
14	Operating Reserve - Spinning	10.86	mills/kWh/month	227.9	**$ 21,680,947**
15	Operating Reserve - Supplemental	9.95	mills/kWh/month	227.9	**$ 19,864,220**
16	Operating Reserve Total			**455.8**	**$ 41,545,167**
17	Synchronous Condensing	$ 28.85	MWh + $288,000	44,397	$ 1,572,849
18	Generation Dropping			1 drop/year	$ 333,061
19	Redispatch				$ 400,000
20	Segmentation of COE/Reclamation Network and Delivery Facilities				$ 7,600,000
21	Station Service	$ 28.85	MWh	82,665	$ 2,384,885
22	Generation Inputs Total				**$ 115,318,568**

Table 2 **Rates for Reserve-Based Ancillary and Control Area Services for FY 2014-2015**			
	A	**B**	**C**
	Rate Name	**Rates**	**Units**
1	**Variable Energy Resource Balancing Service (VERBS) for Wind**		
2	Regulating component	0.08	$/kW-month
3	Following component	0.32	$/kW-month
4	Imbalance component	0.80	$/kW-month
5	**Total VERBS for Wind for Committed 30/60 Scheduling**	1.20	$/kW-month
6	Regulating component	0.08	$/kW-month
7	Following component	0.32	$/kW-month
8	Imbalance component	0.54	$/kW-month
9	**Total VERBS for Wind for Committed 40/15 Scheduling**	0.94	$/kW-month
10	Regulating component	0.08	$/kW-month
11	Following component	0.32	$/kW-month
12	Imbalance component	0.47	$/kW-month
13	**Total VERBS Rate for Committed 30/30 Scheduling**	0.87	$/kW-month
14	Regulating component	0.08	$/kW-month
15	Following component	0.32	$/kW-month
16	Imbalance component	0.33	$/kW-month
17	**Total VERBS Rate for Committed 30/15 Scheduling**	0.73	$/kW-month
18	Regulating component	0.08	$/kW-month
19	Following component	0.32	$/kW-month
20	Imbalance component	1.08	$/kW-month
21	**Total VERBS Rate for Uncommitted Scheduling**	1.48	$/kW-month
22	**Variable Energy Resource Balancing Service (VERBS) for Solar**		
23	Regulating component	0.04	$/kW-month
24	Following component	0.17	$/kW-month
25	Imbalance component	-	Not Applicable
26	**Total VERBS for Solar**	0.21	$/kW-month
27	**Dispatchable Energy Resources Balancing Service (DERBS)**		
28	DERBS Hourly rate *inc*	18.15	mills/kW
29	DERBS Hourly rate *dec*	3.94	mills/kW
30	**Regulation & Frequency Response (RFR)**		
31	RFR Rate	0.12	mills/kWh
32	**Operating Reserves (OR)** also known as contingency reserves		
33	OR spinning rate	10.86	mills/kWh
34	Default Rate (normal rate * 1.15)	12.49	mills/kWh
35	OR supplemental rate	9.95	mills/kWh
36	Default Rate (normal rate * 1.15)	11.44	mills/kWh

BONNEVILLE POWER ADMINISTRATION
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