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 Initial Rate Proposal

Transmission Segmentation Study

November 2012

BP-14-E-BPA-06

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SEGMENTATION STUDY

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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	IntercontinentalExchange
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
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 Bonneville Power Administration (BPA) segments its transmission facilities based on the services those facilities provide and determines the investment and operations and maintenance (O&M) expenses associated with the facilities in the segments. This Study explains how BPA has segmented its transmission system for the fiscal year (FY) 2014–2015 rate period, defines the proposed segments, and determines the investment and O&M expenses for each segment. BPA uses the information developed in this Study to establish the segmented revenue requirement in the Transmission Revenue Requirement Study, BP-14-E-BPA-08. The segmented revenue requirement is then used to set transmission rates in the Transmission Rates Study, BP-14-E-BPA-07.

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2. SEGMENTING THE SYSTEM

BPA has segmented its transmission system for ratemaking purposes since the 1981 rate case. BPA uses a variety of methods to assign transmission facilities to various segments, including:

- Power flow studies and one-line diagrams (schematic drawings of lines and substation layouts)
- Contracts associated with the facilities
- Work orders under which facilities were constructed
- Standard costing procedures and accounting principles

Since 1996, BPA has segmented its facilities into the following segments: Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, and Direct Service Industry (DSI) Delivery. BPA added another segment, Ancillary Services, in the 2002 rate case. These segments are defined in the sections that follow.

2.1 Generation Integration

The Generation Integration segment consists of facilities that connect the Federal generating plants, owned and operated by the U.S. Army Corps of Engineers (COE) or U.S. Bureau of Reclamation (Bureau), to BPA's transmission facilities. This segment includes:

- Transmission lines and equipment between the generator and the first BPA substation at which the power enters the BPA Integrated Network segment
- Substation terminal equipment such as disconnect switches, circuit breakers, and lightning arresters
- Generator step-up transformers, which transform voltage from the voltage at which it is generated to the voltage at which it is transmitted

The purpose of these facilities is to integrate Federal generation onto BPA's transmission system, so the costs associated with these facilities are allocated to and recovered through BPA's power rates.

2.2 Integrated Network

The Integrated Network segment is the core of BPA's transmission system. BPA created the Integrated Network segment in its Cost of Service Analysis for the 1981 rate case. The facilities in this segment transmit power to the Delivery segments and directly to wholesale customers, as well as to and from the Intertie segments and other interconnections with adjacent balancing authority areas. They also integrate major system resources directly or in conjunction with BPA's Generation Integration segment. The Integrated Network segment consists of facilities that serve a transmission function, including sub-transmission, from 34.5 kV to 500 kV. (Sub-transmission facilities are lower-voltage facilities that transfer power from BPA's bulk transmission system to retail utility distribution systems, which then deliver power to retail customers.)

The facilities in this segment do not serve distinct functions like the Generation Integration or Southern Intertie segments do. Instead, they provide services and benefits to nearly all of BPA's customers, including users of both Federal and non-Federal power. Therefore, they are treated as integrated facilities for purposes of cost allocation and cost recovery. The benefits of this segment include displacement (local generation serving load instead of remote generation scheduled to serve that load), bulk power transfers, voltage regulation, and increased overall reliability resulting from alternative resource and transmission pathways. BPA plans and operates these facilities on an integrated basis to achieve maximum efficiency on a system-wide basis.

2.3 Pacific Northwest-Southwest (Southern) Intertie

The Southern Intertie segment is a system of transmission lines that interconnect the Pacific Northwest to California power systems at the Oregon border. This segment consists of a 1,000 kV direct-current (DC) line that originates at the Celilo Converter Station near The Dalles, Oregon, and extends to the Nevada-Oregon border and multiple 500 kV alternating-current (AC) lines that move power primarily from north-central Oregon to the California-Oregon border. BPA owns most of the Intertie facilities north of the California-Oregon and Nevada-Oregon borders. BPA does not own the following major Intertie facilities:

- One of the 500 kV AC lines from Grizzly substation to Malin substation in central Oregon and associated terminals, owned by Portland General Electric Company
- The Meridian-Captain Jack-Malin line and Summer Lake-Malin line and associated terminals, owned by PacifiCorp

BPA had separate charges for use of the Southern Intertie before it began segmenting its system in 1981 because these facilities were primarily used to transmit power out of the Pacific Northwest to California. BPA created a separate segment for these facilities in the 1981 rate case to reflect the fact that their use is distinct from other uses of the system.

2.4 Eastern Intertie

The Eastern Intertie segment consists of the Garrison-Townsend 500 kV line and the associated substation facilities at Garrison. These facilities provide an additional interconnection in Montana (primarily for the Colstrip generating plant) to the Integrated Network. These facilities were built according to the Montana Intertie Agreement, which provides that the costs associated with building and maintaining these facilities would be allocated to the parties to the agreement.

2.5 Utility Delivery

The Utility Delivery segment consists of substation facilities required to "step down" (reduce) transmission voltages to delivery voltages below 34.5 kV. Step-down transformers and associated switching and protection equipment constitute the majority of facilities included in this segment. These facilities are generally located at a customer's point(s) of delivery.

2.6 Industrial Delivery

This segment is similar to the Utility Delivery segment but consists of facilities that step down transmission voltages to delivery voltages below 34.5 kV at locations where power is supplied to BPA's direct-service industrial (DSI) customers. Because these facilities serve a distinct purpose of supplying power to DSI customers, BPA has segmented these facilities separately and allocated their cost to the DSI customers that use them.

2.7 Ancillary Services

This segment consists of control and associated communication equipment necessary for BPA to provide Scheduling, System Control, and Dispatch (SCD) services. This equipment includes monitoring and supervisory control equipment, associated communication equipment, and control center hardware and software. Because this equipment serves a distinct purpose of supporting BPA's provision of SCD services, BPA has assigned it to the Ancillary Services segment and recovers its costs through the SCD rate.

3. DETERMINING INVESTMENT AND O&M EXPENSES FOR THE SEGMENTS

In addition to defining the segments on BPA's system, this Study also determines the gross plant investment and historical O&M expenses associated with facilities within the segments. (BPA assigns some stations and transmission lines to multiple segments, as described in section 3.1.2 below.) The segmented gross plant investment is needed to calculate the segmented depreciation expense and interest expense for the rate period. The segmented historical O&M expenses are needed to allocate the O&M expenses for the rate period across the segments. Establishment of the segmented revenue requirement is described in the Transmission Revenue Requirement Study, BP-14-E-BPA-08.

3.1 Gross Plant Investment in Existing Facilities

BPA determines the gross plant investment in all existing transmission facilities as of the end of the most recent fiscal year when the segmentation study is done (FY 2011 for this rate period). This investment includes both transmission plant and general plant investments. Transmission plant investment refers to investment in lines and substations, which are defined in FERC account nos. 352 through 359. General plant investment refers to investments in general equipment, such as communications equipment and office furniture, and is defined in FERC account nos. 390 through 398.

BPA uses the following resources to determine investment for station and transmission line equipment:

- Plant investment records identify the investment for the equipment at each facility.

- One-line diagrams indicate the operating voltage or specific use of facilities. One-line diagrams are used to identify the number, location, and characteristics (such as voltage) of various breakers and transformers.
- Installation and maintenance records identify major equipment installed or maintained by BPA. These records are used to identify and associate specific equipment in the plant accounting records with that on the one-line diagrams. This association is particularly useful in allocating investment at facilities that support more than one function and whose costs are allocated to more than one segment. Facilities that support more than one function are described in more detail in section 3.1.1, below.
- Power flow studies model the actual flows of power over various transmission lines after power is injected into the transmission system.
- Several of BPA's agreements (*e.g.*, agreements relating to the construction and operation of the Southern and Eastern Interties) specify how the costs for certain facilities should be recovered.

3.1.1 Multi-segmented Facilities

For facilities serving more than one segment (multi-segmented) it is necessary to pro-rate the investment between the segments. Generally, BPA uses the following process to allocate the investment of multi-segmented facilities:

1. The investment in major components (*e.g.*, circuit breakers, transformers, and reactive equipment that is tracked separately in the investment records) is grouped by equipment type and voltage level. A group may support multiple terminals. (Terminals are the points where transmission lines terminate in a substation. Terminals are segmented based on the segmentation of the associated transmission line.) For example, a substation may have 230 kV equipment

supporting both Integrated Network and Generation Interconnection terminals, and reactive equipment supporting only the Integrated Network segment. The major equipment investment is separated into two groups accordingly (a 230 kV shared group and a reactive group).

2. The investment in remaining common equipment for the substation, such as buildings and fences, is pro-rated to each group based on the investment in major equipment. In the example above, if the 230 kV shared group has been assigned 80 percent of the investment in major facilities, it is also assigned 80 percent of the investment in common equipment.
3. The investment in each shared group is pro-rated between the segments based on the number of terminals that are identified with each segment. Since terminals are electrically interchangeable, the cost of the shared group is assumed to be shared equally among the terminals. Using the above example, if the 230 kV shared group supports four Network terminals and two Generation Interconnection terminals, two-thirds (4 of 6 terminals) of the 230 kV shared group investment is allocated to the Network segment, and one-third (2 of 6 terminals) is allocated to the Generation Interconnection segment.
4. A group that supports only one segment is allocated entirely to that segment. In the example above, the reactive equipment investment with its pro-rated common equipment would be allocated entirely to the Network.
5. The percentage share of the multi-segmented facility’s investment that has been assigned to each segment is calculated. This percentage share is also used to allocate the historical O&M associated with the facility. For example, if the substation’s total investment is $5,000,000, and 90 percent (or $4,500,000) has been assigned to the Network segment, then 90 percent of the historical O&M is also assigned to the Network segment.

3.1.2 Facilities Not Directly Associated with Segments

Some transmission plant investment is not assigned to a particular segment because it cannot be identified with a particular function or service. For example, emergency equipment spares that support multiple segments are not assigned to particular segments.

The plant investment associated with these facilities is allocated to all the segments on a pro-rata basis. For example, if 80 percent of the directly assigned investment in station equipment is segmented to the Integrated Network segment, then 80 percent of the indirect investment in station equipment is also segmented to the Integrated Network. The Documentation for the Transmission Segmentation Study (Documentation), BP-14-E-BPA-06A, Table 2, lines 4 and 19, shows the allocation of the investment in these facilities.

3.1.3 Intangible Investment

Intangible investments are BPA's share of participation in facilities owned by others (capacity rights). As shown in Documentation Table 1, BPA has $9.6 million of intangible investments. They are segmented to either the Integrated Network or Southern Intertie based on the function each facility supports.

3.1.4 Land Investment

Land is typically not depreciated, and therefore no amortized costs for land need to be segmented. However, BPA does have some leased land that is depreciable ($43.3 million) and, therefore, needs to be segmented. The majority of this land supports transmission lines (rights-of-way) and is segmented according to the function of the associated line investment. For example, leased land that supports a transmission line segmented to the Integrated Network is also segmented to the Network. *See* Documentation Table 1.

BPA has some depreciable leased land ($568,000) associated with a radio station that is not segmented to a specific segment but is prorated to the segments based on the total of the line and station investment allocated to each segment, similar to general plant investment described in section 3.1.6, below.

3.1.5 Ancillary Service Investment

As shown in Documentation Table 1, BPA has $168 million in ancillary service investment. This investment includes equipment designated as control equipment ($77.9 million), hardware and software at the control centers supporting scheduling and dispatch ($31.0 million), and communication equipment supporting Supervisory Control and Data Acquisition (SCADA) ($59.3 million). This investment is all allocated to the Ancillary Services segment. *Id*. Table 2.

3.1.6 General Plant Investment

General plant investment is associated with equipment of a general nature (FERC accounts 390 through 398). BPA's maintenance headquarters and BPA's telecommunication system facilities (radio stations) are examples of general plant. Through FY 2011, BPA has a general plant investment of $730 million. The depreciation cost associated with general plant investment is allocated pro-rata (based on the directly assigned investment) to the segments on a net plant basis (after depreciation) in the Transmission Revenue Requirement Study, BP-14-E-BPA-08.

3.2 Future Plant in Service

In order to estimate the investment that will be in place during the FY 2014–2015 rate period, the historical investment is adjusted to remove investment in facilities expected to be retired or sold and to include the forecast installation of new facilities during the rate period. Documentation Table 3 summarizes the expected station and line investment for fiscal years 2012 through 2015. New facility investment is identified from BPA's Integrated Programs in Review (IPR) process. No specific facilities are identified for retirement in this Study. However, in the Transmission Revenue Requirement Study, the expected investment in new station facilities is reduced based on historical ratios of retired equipment to new replacement equipment. Transmission Revenue Requirement Study Documentation, BP-14-E-BPA-08A, Chapter 4.

3.3 Operations and Maintenance Expense

This Study includes historical O&M expenses from plant record data for the last three fiscal years (2009, 2010, and 2011). Averaging the last three years of data instead of using only the most recent year minimizes potential biases, such as scheduling or weather anomalies in a particular year. The historical segmented O&M expenses averaged $147.8 million annually. Documentation Table 4. The O&M expenses that are segmented include transmission operations costs associated with substation operations and all costs for transmission maintenance, including environment expense.

A few categories of historical O&M expenses are identified in this Study but are not segmented. Forecast scheduling costs and system operations costs associated with dispatch are directly assigned to the Ancillary Services segment because these costs are related to providing Scheduling, System Control, and Dispatch service. Forecast marketing and business support costs are allocated on a net plant basis (pro-rata, based on the directly assigned investment) to the segments because these costs are overhead costs and are not associated with specific facilities. The treatment of these forecast costs for ratemaking purposes is addressed and described in more detail in the Transmission Revenue Requirement Study, BP-14-E-BPA-08. The historical O&M expenses associated with these categories are shown in this Study for informational purposes.

The historical Ancillary Services O&M expenses averaged $42.4 million annually. The historical marketing and business support expenses averaged $42.1 million annually. Documentation Appendix C, Tables 2 and 3.

3.3.1 Historical O&M Assignment to Facilities

BPA uses the following process to assign historical O&M expenses to the segments:

1. Approximately one-third of historical O&M expenses set forth in BPA's accounting records directly identify the facility being supported. *Id.* Table 4. The directly identified O&M expenses for each fiscal year are broken down by category (*e.g.*, programs within BPA's transmission business line, substation operations, or transmission line maintenance) and facility type (*e.g.*, transmission lines, substations, metering stations). *Id.* Tables 6, 8, and 10.
2. Non-identified O&M expenses (that is, expenses not identified with a specific facility, *Id.* Table 5) are determined for each category and fiscal year by subtracting the directly identified O&M expenses (*Id.* Table 4) from the total O&M expenses (*Id.* Table 1).
3. For those categories that have both directly identified and non-identified expenses, the non-identified portion within each category is pro-rated to

each facility type in proportion to the directly identified expenses for each facility type. *Id.* Tables 7, 9, and 11.

4. Some categories of O&M expenses have no directly identified facilities (Right-of-Way Maintenance, Technical Training, Vegetation Management, and Environmental Analysis). The total for these categories is identified by fiscal year. *Id.* Table 5, line 77. This total is allocated in proportion to the total of directly identified expenses for each facility type. *Id.* Tables 7, 9 and 11, lines 94, 121, and 140.

5. An annual total O&M expense is calculated for each facility type by adding the directly identified expenses in step 1 and the non-identified expenses in steps 3 and 4, above, for each fiscal year. *Id.* lines 95, 122, and 141.

6. The total expense for each facility type is divided by the directly identified expenses to determine an annual multiplier for each facility type. *Id.* lines 96, 123, and 142.

7. The directly identified annual O&M expense for each facility type is multiplied by the annual multiplier for the facility type, and the three-year average is the assigned historical O&M expense. The historical facility O&M expenses are then allocated to segments according to the percentage of the investment in each facility type that has been allocated to that segment. Documentation Appendix A.

3.4 U.S. Army Corps of Engineers and U.S. Bureau of Reclamation Facilities

The investment and annual O&M expenses for the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation facilities that function as part of BPA’s transmission system are included in the transmission revenue requirement, even though BPA does not own these facilities. The segmentation of these costs is described in the Generation Inputs study, BP-14-E-BPA-05, section 8.

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