BP-16 Initial Rate Proposal

Transmission Rates Study and Documentation

BP-16-E-BPA-07

December 2014

TABLE OF CONTENTS

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER step	Actual Energy Regulation study
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPA-P	Bonneville Power Administration – Power
BPA-T	Bonneville Power Administration – Transmission
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
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
DOP	Detailed Operating Plan
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
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GMS	Generation Management Service
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
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
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)
NRFS	New Resource Flattening Service
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
OPER step	operational study
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
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION TO THE TRANSMISSION RATES STUDY

1.1 Purpose

The Transmission Rates Study describes the rate design process and the calculations used for developing the transmission rates for BPA's wholesale transmission services for fiscal years (FY) 2016 and 2017. The primary purpose of this study is to demonstrate that the rates have been developed in a manner consistent with statutory directives and will recover the transmission revenue requirement for the rate period. The transmission rates can be found in the 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10.

This study also discusses the development and calculation of rates for two ancillary services that are associated with transmission service: (1) Scheduling, System Control, and Dispatch (SCD) Service, and (2) Reactive Supply and Voltage Control from Generation Sources Service (also known as Generation Supplied Reactive (GSR) Service). The Generation Inputs Testimony, BP-16-E-BPA-12, discusses the generation input settlement proposal and services under the proposal.

This study is organized into seven sections. The first is this introduction, which includes a discussion of the statutory and contractual basis for the rate development and an overview of the rate design process and methodology. Section 2 describes the sales and revenue forecasts used to calculate the rates for network and intertie services. Section 3 describes revenue credits and other adjustments that are applied to the revenue requirements. Section 4 describes the calculation of the rates for transmission service over the Network segment. Section 5 describes the calculation of the rates for intertie transmission services. Section 6 describes the calculation of the rates for SCD and GSR services. Section 7 discusses other transmission services and the General Rate Schedule Provisions (GRSPs). The Transmission Rates Study includes the documentation to support the calculations performed in this study.

1.2 Basis for Rate Development

1.2.1 Statutes

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

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

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

- insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the FCRTS. *Id.* § 839e(a)(2).

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

Section 212(i) of the Federal Power Act sets forth additional ratemaking requirements for transmission rates for transmission service ordered by the Commission. *Id.* § 824k(i). Section 211A of the Federal Power Act authorizes the Commission to require unregulated transmitting utilities (including BPA) to provide transmission service at rates comparable to those that the unregulated transmitting utilities charge themselves. *Id*. § 824j-1.

1.2.2 Existing Contractual Arrangements

The transmission rates developed in this study will apply to existing and new service agreements established under BPA's Open Access Transmission Tariff (OATT), as well as legacy (grandfathered, pre-FERC Order 888) transmission service contracts, for the FY 2016–2017 rate period. For some contracts, such as Direct Service Industry (DSI) delivery contracts, rates change according to a contract schedule independent of the rate proceeding. Under those contracts, new rates will apply only if the rate is due to change under the contract schedule. Other contracts, such as Operations and Maintenance (O&M) and Use-of-Facilities (UFT) contracts, are fixed-price or formula rate contracts and are not affected by the rate design process discussed in this study.

1.3 Overview of Transmission Rate Design Process and Methodology

BPA establishes transmission rates by determining the overall costs of the transmission system (revenue requirement) and allocating those costs to its various customer classes through processes of segmentation (discussed below) and cost allocation. The costs allocated to the various segments are then divided by the forecast usage of those segments to derive transmission rates.

This study relies on the results of the Transmission Segmentation Study and the Transmission Revenue Requirement Study to calculate the rates. Sections 1.3.1 and 1.3.2 provide an overview of these studies.

1.3.1 Transmission Segmentation Study

BPA divides its transmission system into segments such that transmission facilities that serve different uses are assigned to different segments. The Transmission Segmentation Study explains how BPA established its segments for the FY 2016–2017 rate period and determined the investment and O&M expense ratios for each segment. BPA has established seven segments for the purposes of developing rates for the rate period: Generation Integration, Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Ancillary Services.

The segmented investment ratios (the percentage of total net plant investment represented by each segment's plant investment) and O&M cost ratios (the share of total O&M costs represented by each segment's historical O&M costs) identified in the Transmission Segmentation Study are inputs to the Transmission Revenue Requirement Study, where they are used to determine the portion of the transmission revenue requirement that is allocated to each segment.

1.3.2 Transmission Revenue Requirement Study

The Transmission Revenue Requirement Study establishes the amount of revenue needed to recover the costs associated with providing transmission services for the rate period. The revenue requirement is based on program-level expenses and capital expenditures developed in the 2014 Capital Investment Review and Integrated Program Review (IPR) processes, which preceded the rate development process.

The Transmission Revenue Requirement Study determines the revenue requirements for each segment (the segmented revenue requirement) by applying the investment and O&M ratios developed in the Transmission Segmentation Study to the overall transmission revenue requirement. The segmented transmission revenue requirement for FY 2016–2017 is shown in table 1 in this study. Section 2 of the Transmission Revenue Requirement Study describes this allocation.

BPA has discovered an error in the BP-14 rate case in the allocation of O&M costs among the Generation Integration, Network, Southern Intertie, Utility Delivery, Eastern Intertie, and DSI segments. BPA is proposing to correct the BP-14 error in the BP-16 rates. The correction is explained in section 3.4.

1.3.3 Transmission Rates Study

Development of the rates for the transmission and ancillary services addressed in this study relies on two primary inputs: (1) sales forecasts developed as part of the study; and (2) the segmented transmission revenue requirements developed in the Transmission Revenue Requirement Study. The study takes the segmented transmission revenue requirements, allocates these revenue requirements to the various transmission services, and divides the allocated revenue requirements by the sales forecasts for each transmission service developed in the rates study to calculate a rate for each service. This study demonstrates that the rates have been developed in a manner consistent with statutory directives and that they will recover the allocated transmission revenue requirement for the rate period.

2. SALES AND REVENUE FORECASTS

2.1 Overview

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

BPA prepared two revenue forecasts for the rate period (FY 2016–2017), one forecasting the revenue at current (BP-14) rates and the other at proposed (BP-16 Initial Proposal) rates. These revenue forecasts are used in the Transmission Revenue Requirement Study to test whether current rates are sufficient to recover the transmission revenue requirement and whether proposed rates are sufficient to recover the transmission revenue requirement. *See* Transmission Revenue Requirement Study, BP-16-E-BPA-08, § 3.

Sales forecasts are discussed further in sections 2.2, 2.3, 2.4, and 2.5 below and are shown on tables 4, 5, 9, 10.1, 13.1, 13.2, 14, and 15 in this study. Revenue forecasts are discussed further in section 2.6, and the revenue forecasts at current and proposed rates are shown in table 12.

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

2.2 Sales Forecasts for Transmission Service on BPA's Network

Sales forecasts for long-term transmission services are generally based on measures of use to which the charges for the service are applied. Sales forecasts of Network Integration (NT) transmission service are based on load forecasts because the charges for this transmission service are based on the customers' loads. Sales forecasts of long-term Point-to-Point (PTP) transmission service, Integration of Resources (IR) transmission service, and Formula Power Transmission (FPT) service are based on transmission contract demand or reserved capacity because the charges for these services are based on the demand or capacity amounts specified in the customers' transmission contracts. BPA includes both existing sales and expected future sales in the forecasts.

Because short-term PTP service is not reserved far in advance, there are no existing reserved capacities during the rate period on which to base the sales forecast. Instead, the forecast is based on the statistical relationship between historical short-term sales data and historical price spread and streamflow data. It is assumed that the historical relationship represents the future relationship between short-term sales and streamflow and forecast price spread. The methodology for forecasting sales for each transmission service is discussed in more detail below.

2.2.1 Sales Forecast for NT Transmission Service

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

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

BPA uses a multi-step process to determine NT customers' non-coincident peak POD load forecasts. Steps 1 and 2 describe how BPA determines the customer's maximum hourly load at the customer's PODs during each month of the rate period. Steps 3 and 4 explain how BPA adjusts the maximum hourly load forecast to determine the sum of the hourly load at the customer's PODs on the hour in which this sum is the highest (the highest hourly load). The non-coincident peak load forecast is used for the Network segment cost allocation, described in section 4.

Step 1: Regression Analysis of Historical Meter Readings

First, BPA uses a regression analysis to identify the historical relationship between POD load levels and temperature. A regression analysis evaluates how one variable (in this case load levels) changes, given changes in independent variables (such as temperature). The regression analysis identifies the statistical relationship between historical load levels at individual PODs and temperature, among other variables. For historical load level data, the analysis typically uses historical monthly meter readings from individual PODs from 1999 to 2013, a period of time that includes a large enough sample to perform meaningful statistical analysis. A shorter period is used for any customer for which these years would not accurately reflect load growth, such as a customer that added a sizeable new load in recent years.

For temperature data, BPA uses actual historical temperatures from National Oceanic and Atmospheric Administration weather stations from the same time period. For each

POD, the analysis uses temperature data from a weather station near the POD and identifies the relationship between the load levels and temperature. The model confirms that both increasing and decreasing temperatures can result in increasing load levels. Increasing temperatures lead to greater use of air conditioning during warm weather periods, while decreasing temperatures lead to greater use of heating equipment during cold weather periods.

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

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

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

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

For the second step, BPA forecasts the maximum hourly load at each POD in the customer's contract for each month of the billing period, using the relationships identified in the regression analysis. BPA inputs into the model independent variables that represent possible future conditions. The variables include a temperature indicator, the monthly indicator, and time trend variables discussed above.

A temperature indicator is the average heating degree days and cooling degree days. Heating and cooling degree days are calculated from daily average temperatures between 1970 and 2004 and area base temperatures for the geographic area. The daily average temperature is the average of the daily minimum and maximum outdoor temperatures on a given day. The area base temperature is the temperature that reflects the use of heating and cooling equipment in that area and other characteristics of the residential, commercial, and industrial load. Heating degree days are days that the daily average temperature is below the area base temperature for the geographic area. Cooling degree days are days that the daily average temperature is above the area base temperature for the geographic area. There is a positive relationship between heating and cooling degree days and load change. More heating degree days mean colder than average temperatures and higher loads from increased use of heating equipment. More cooling degree days mean warmer than average temperatures and higher loads from increased use of air conditioning equipment.

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

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

Step 3: Adjustment of Maximum Hourly Load at the PODs

Because the maximum hourly load at each POD may not occur on the hour of the month in which the sum of the customer's load at all of its PODs is highest, BPA adjusts the forecast of the maximum hourly load at each POD by a coincident factor for each month. The coincident factor for each month for each POD is the average of the ratios of the historical POD load on the hour of the customer's monthly peak load to the historical POD load on the hour of that POD's peak load during the same month, for the same years used for the regression analysis (typically 1999 to 2013). BPA multiplies the forecast of the maximum hourly load for the month at the POD by its coincident factor to determine the forecast POD load on the hour of the customer's peak load for the month.

Step 4: Determination of Customer's POD load forecast

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

2.2.1.2 Determination of Customer's Coincident Peak POD Load Forecast

BPA forecasts the customer's coincident peak load on the hour of the monthly BPA transmission system peak to calculate the rate and to develop the sales forecasts to forecast revenue at the current and proposed NT rate. BPA develops the coincident peak forecast using the same methodology used for the non-coincident peak POD load forecast described above in steps 1 and 2 of section 2.2.1.1 (BPA does not use steps 3 and 4). Next, BPA adjusts the maximum hourly load forecast for the POD to reflect the load on the hour of BPA's monthly transmission system peak. (The billing factor for the NT-16 rate is the customer's load on the hour of BPA's monthly transmission system peak.) These sales forecasts are shown in table 4, lines 15-18, 33-36, and 48-51. The forecast of revenue at current rates is shown in table 12.

2.2.1.1 NT Sales Forecast

As noted above, the study develops a non-coincident peak NT load forecast for cost allocation and a coincident peak NT load forecast to calculate the NT rate for the NT sales forecast used in the revenue forecast. *See* table 4 (the non-coincident peak NT load forecasts developed in section 2.2.1.1 for FY 2016 and 2017 and the average over the rate period is shown in lines 16, 34, and 49; the coincident peak load forecasts developed in section 2.2.1.2 for FY 2016 and 2017 and the average over the rate period are shown in lines 12, 30, and 45).

For the Network segment cost allocation (described further in section 4), BPA reduces the monthly non-coincident peak load forecasts to reflect the impact, in megawatts, of the NT Short Distance Discount (SDD). The SDD applies to a customer's Network Resources that are designated for at least 12 months and that use FCRTS facilities for less than 75 circuit miles for delivery to Network Load. BPA forecasts a reduction in sales due to the SDD by multiplying the average generation of the designated network resource during heavy load hours (HLH) by the SDD formula of 40% × (75 – distance) / 75. *See* table 4 (forecast NT SDD during the rate period is shown in lines 10 and 28).

For the revenue forecast and to calculate the NT rate (discussed further in section 4), BPA reduces the monthly coincident peak load forecasts to reflect the impact, in megawatts, of the NT SDD. *See* table 4 (forecasts developed in section 2.2.1.2 for FY 2016 and 2017 and the average over the rate period, including a reduction for the NT SDD, are shown in lines 13, 31, and 46). BPA uses the average of the monthly coincident peak load forecasts, including a reduction for the NT SDD, for each fiscal year.

To calculate the NT SCD and GSR Ancillary Services rates (discussed further in section 6), the study uses the average of the monthly coincident peak load forecasts, not including a reduction for the NT SDD.

2.2.2 Sales Forecast for PTP Transmission Service on the Network

Point-to-Point transmission service provides for the transmission of energy on a firm or non-firm basis from specific point(s) of receipt to specific point(s) of delivery under

Part II of BPA's OATT. PTP service may be long-term (one year or longer) or short-term (hourly, daily, weekly, or monthly service). BPA separately forecasts sales of long-term and short-term PTP transmission service on the Network.

2.2.2.1 Long-Term PTP Transmission Service Sales Forecast

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

(a) current long-term reserved capacities effective through the FY 2016–2017 rate period. This forecast includes all confirmed reservations for service during the rate period, including confirmed reservations for Conditional Firm Service; and

(b) current long-term firm reserved capacities with start dates that have been deferred pursuant to OATT section 17.7 (extensions for commencement of service), which reduce the sales forecast for the period of the deferral.

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

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

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

(c) current requests for long-term PTP service for which BPA expects to offer Conditional Firm Service during the rate period;

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

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

In forecasting expected additional long-term PTP sales on the Network, BPA also considers a variety of other sources of information. BPA examines requests in the queue. BPA consults with customers, account executives, and others with knowledge about long-term PTP requests concerning expected service demand, start date, length of the service, and whether the customer is expected to accept the offer. BPA also considers the potential for additional sales as a result of new or changed business practices that are expected to be in effect during the rate period. The forecast reflects the most likely scenario based on this information. If there is a great deal of uncertainty in the information gathered through this process, BPA looks at historical sales to the customer to determine whether the additional sales should be included in the forecast.

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

The study calculates the average of the monthly sales forecasts, including the reduction for the SDD, over the rate period and for each fiscal year. The average of the monthly sales forecasts for each fiscal year, including the reduction for the SDD, is used to establish the revenue forecast from long-term PTP sales. The average of the sales forecasts over the rate period, not including the reduction for the SDD, is used for the Network segment cost allocation, discussed in section 4.

The study uses the average PTP sales forecast for each fiscal year, not including the reduction for the SDD, to calculate an average for the rate period, which is used to establish the sales forecast for SCD and GSR services (described further in section 2.4). *See* table 4.

2.2.2.2 Short-Term PTP Network Sales Forecast

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

BPA develops the forecast of short-term PTP sales in three steps. First, BPA performs a regression analysis of historical data to identify the relationships between sales, market indicators, and seasonality (that is, how sales change given changes in streamflow, price spread, and seasonality). Second, BPA identifies the sets of data (streamflow, future market price spread, and seasonality) to be used as inputs to the short-term sales forecasting model. The forecasting model is based on the regression analysis performed in the first step. Third, BPA develops the forecast of short-term sales.

This method develops a forecast that reflects (1) historical relationships between sales and market indicators and (2) expected market conditions over the rate period. The model assumes that historical relationships between sales and streamflow, price spread, and seasonality represent future relationships. Streamflow and price spread data are input to the model to predict future conditions, and with those inputs and adjustments for variability, the historical correlation is projected into the future to produce a sales forecast.

Step 1: Regression Analysis of Historical Data

First, BPA performs a regression analysis, using R® computer software (www.r-project.org), to determine the statistical relationship between historical short-term PTP sales and market indicators (streamflow, price spread, and seasonality). R® is an open source (that is, free) software program used for statistical analysis that supports the development of risk models. BPA performs one regression analysis for BPA Power Services' short-term PTP reservations and another analysis for all other customers' short-term PTP reservations.

For short-term PTP sales to customers other than BPA Power Services, BPA performs the regression analysis on historical short-term PTP sales against streamflow, price spread, and seasonality. For these customers, there is a significant statistical relationship between sales and streamflow, price spread, and seasonality. These customers are more likely to sell power (and purchase short-term transmission to do so) when streamflow conditions are high, when pricing conditions provide incentives to market power, and in certain months (particularly May through July). They are less likely to sell power and purchase short-term transmission when the price spread is too low to allow them to produce a profit and recover the cost of the additional transmission purchases, when streamflow at The Dalles is low, or in the fall and winter months. The analysis uses historical data from October 2006 through April 2014 for all sets of data—sales, streamflow, price spread, and seasonality.

To determine streamflow, BPA uses historical regulated streamflow at The Dalles, obtained from the U.S. Geological Survey (USGS), because it is an indicator of the amount of power that will be generated and sold using short-term PTP service. In general, higher historical streamflows correlate with higher sales of short-term PTP service.

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

Finally, to determine seasonality, BPA uses the calendar month in the regression because even if streamflow and price spreads remain constant from month to month, sales in certain months are higher than sales in other months. In general, sales in May through July are higher than sales in all other months, and sales in October are lower than sales in all other months.

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

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

As the second step in developing the forecast, streamflow, price spread, and seasonality data are used as inputs to forecast short-term sales. These inputs represent expected future market conditions. For the input for streamflow conditions, the model uses average streamflow at The Dalles from 1950 through 2003. This dataset has streamflow data for each month in each of those years. It is a large enough sample size to account for short-term variations in the data, and it provides a reasonable potential range of streamflow scenarios in the rate period.

As the input for price spread conditions, Mid-C and NP-15 prices obtained from the AURORAxmp® model are used to represent expected power prices during the rate period. The AURORAxmp® model is described in the Power Risk and Market Price Study, BP-16-E-BPA-04, section 2. The Mid-C forecast price is subtracted from the NP-15 forecast price to obtain the price spread input to the forecasting model to predict future sales. This methodology is consistent with the use of the historical NP-15 minus Mid-C price spread used in the regression analysis.

To account for seasonality, the model incorporates dummy variables (a multiplier that represents seasonal short-term reservation behavior, controlling for the effects of streamflow and price spread) to capture the monthly trends of short-term sales observed in the first step. Because sales are generally highest in May through July, the monthly dummy variables in those months are higher than they are the rest of the year.

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

The way the model uses the inputs is described further in step 3 below.

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

BPA assumes that historical statistical relationships between sales, streamflow, price spread, and seasonality represent future statistical relationships. To forecast short-term sales to Power Services, historical streamflow is input to the model as a prediction of future conditions, and the regression model estimates future sales to produce a sales forecast. To forecast short-term sales to all other customers, historical streamflow and forecast price spread are input to the model as predictions of future conditions. In both cases, the sales forecasts are modeled to include variability, as discussed below.

Short-term sales are variable because they do not require long-term commitments and instead are purchased on an hourly, daily, weekly, or monthly (less than 12 months) basis. Short-term sales forecasts are also subject to uncertainty due to variability in streamflow and price spread.

To account for the impact of variability in short-term sales, BPA incorporates uncertainty around the streamflow, price spread, and other parameters using a Microsoft Excel add-in, @RISK®, Professional version 6.1.1 (© Palisade Corporation). @RISK uses a Monte Carlo-based simulation (a method that uses repeated simulations, called games, to determine a range of possible outcomes) to run 5,000 short-term sales forecasting games and generate the distribution of the outcomes of those games around a mean. In running these games, two sources of uncertainty are modeled, both of which affect the short-term sales forecast: (1) uncertainty in the statistical relationships (that is, the risk of error in the regressions); and (2) uncertainty of input data (streamflow and price spread variability). The final short-term sales forecast is the average of the outcomes (sales forecasts) of all the games.

The variability in the statistical relationships (regression error) is the risk that the regression models provide an imperfect prediction of short-term reservation behavior based on short-term sales and the market indicators. Comparing the actual short-term reservations from the historical dataset and the regression predictions from the same time period indicates the possible magnitude of error. Regression error is modeled to reflect the fact that the regressions cannot accurately predict sales 100 percent of the time. The impact of this variability on the forecast of short-term sales to BPA Power Services is modeled separately from the modeling for other customers, consistent with the analysis outlined above.

To estimate the variability around the correlation between short-term sales to Power Services and streamflow, the model is applied to predict what the short-term sales forecast for Power Services would have been for October 2007 through May 2012, based on streamflow data at The Dalles for that time period. The model's prediction is then compared to actual short-term sales to Power Services for the same time period. The difference between predicted sales and actual sales indicates the possible magnitude of variability between the sales forecast and actual short-term sales. The difference (the standard error of the regression) is input into the model as an indicator of the range of possible error in the correlation between short-term sales and streamflow. This allows the model to generate a range of possible outcomes to account for possible error in the regression.

BPA also models the impact of variation in the forecast market indicators that are used to develop the sales forecast. BPA models variability in streamflow using the 1950–2003 streamflow dataset for the Columbia River at The Dalles. For each Monte Carlo game and for each year of the rate period, @Risk® randomly chooses one year of streamflow data from the overall set of data and uses the data from each month of that year to simulate the streamflows in each month of the simulated rate period year.

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

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

As also noted above, the model produces forecasts of total short-term PTP sales (to Power Services and to all customers other than Power Services) for each month of the year. BPA then allocates total short-term sales across the different short-term services (monthly, weekly, daily, and hourly service), resulting in a forecast for sales under the Hourly, Block 1, and Block 2 rates for each month of the rate period. This allocation is based on the historical distribution of short-term sales across the three rates, using historical data from October 2006 through April 2014 (the same data used to forecast total short-term sales). The historical distribution of sales under each rate is applied to the total short-term sales forecast. The forecasts for sales are then summed to determine overall short-term PTP sales forecasts for each month under each rate. The forecast of short-term PTP sales is shown in table 5.

The fiscal year averages of the sales forecasts for each rate are used to forecast revenues. One further adjustment is made to the sales forecasts for rate development purposes, as described in section 4. The average sales forecast (including the sales for all three rates) over the rate period, including this adjustment, is used for the Network segment cost allocation and in the sales forecast for SCD and GSR.

2.2.3 Sales Forecast for IR Transmission Service

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

The sales forecast of IR service is the sum of the contract demands in each IR contract. For IR agreements that expire during the rate period, the forecast includes only the revenues associated with the agreements while they are in effect. During the rate period, BPA anticipates consistent IR sales of 266 MW. *See* table 4. Before the rate period, IR agreements totaling 967 MW will expire. BPA expects all of the expiring IR agreements to convert to OATT service on the Network. BPA includes expected conversions in the sales forecasts for OATT service on the Network by increasing the PTP sales forecast by the number of megawatts expected to convert to OATT service.

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

2.2.4 Sales Forecast for FPT Service

Formula Power Transmission contracts are transmission service agreements that provide firm transmission of non-Federal power on the Network for both full-year and partial-year service. The forecast of sales of FPT service is the sum of the contract demands in each FPT contract. For FPT agreements that expire during the rate period, the forecast includes only the sales associated with the agreements while they are in effect. During the rate period, FPT agreements totaling 32 MW will expire. This figure is shown in the reduction in the FPT sales forecasts for FY 2016 and 2017 in table 4. BPA expects the agreements that are expiring to convert to OATT service on the Network. BPA includes expected conversions in the sales forecasts for OATT service on the Network by increasing the PTP sales forecast by the number of megawatts expected to convert to OATT service. The adjustment for each contract is made beginning with the month that the FPT contract expires. The fiscal year averages of the sales forecasts are used to forecast revenues. The sales forecast for FPT is not used for the Network segment cost allocation or in the sales forecast for SCD and GSR, as described in sections 2.4 and 4.1.

2.3 Sales Forecasts for Transmission Service on BPA's Interties

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

2.3.1 Sales Forecast for IS Transmission Service

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

2.3.1.1 Sales Forecast for Long-Term IS Transmission Service

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

(a) current confirmed long-term reserved capacities effective through the FY 2016–2017 rate period; and

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

Long-term capacity on the Southern Intertie is fully subscribed, meaning that BPA cannot make additional sales unless existing agreements terminate or are not renewed, or until reliability upgrades on the Pacific DC Intertie increase transfer capability. As a result, the forecast of additional expected long-term IS sales is based on:

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

(b) expected OATT section 17.7 deferrals during FY 2016–2017 (extensions for commencement of service), which reduce the long-term IS sales forecast for the duration of the deferral; and

(c) expected additional long-term sales after December 2016 as a result of a reliability upgrade on the Pacific DC Intertie.

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

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

2.3.1.2 Sales Forecast for Short-Term IS Transmission Service

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

The forecast of short-term IS sales is developed using the same two-step process that is used to develop the forecast of short-term PTP sales, with three primary differences. First, the regression used for short-term IS sales compares historical short-term IS sales to the historical streamflow, price spread, and seasonality data, rather than using historical short-term PTP sales data. Second, short-term IS sales to BPA’s Power Services and all other customers are modeled with historical streamflow, price spread, and seasonality in the same regression analysis and forecasting model, because there is a correlation between streamflow, price spread, and seasonality and short-term IS sales. Similarly, the analysis used for forecasting hourly sales and sales under the Block 1 and Block 2 rates to customers other than Power Services in the short-term

PTP model is the same analysis used for all customers (Power Services and other customers) in the short-term IS model.

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

2.3.2 Sales Forecast for IM Transmission Service

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

The forecast of IM rate sales is based on contract demand. The IM sales forecast during the FY 2016–2017 rate period totals 16 MW of existing long-term sales in each year of the rate period. BPA does not forecast any additional long-term IM sales.

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

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

2.4 Sales Forecasts for Ancillary Services: SCD and GSR

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

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

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

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

The short-distance discount associated with NT and PTP service does not apply to SCD and GSR sales. Therefore, the sales forecast for SCD and GSR is not adjusted to reflect the SDD. The sales forecast used for developing the SCD rate is shown in table 10.1. The same sales forecast is included in the formula in the GSR rate schedule. *See* Transmission, Ancillary, and Control Area Service Rate Schedules, BP-14-E-BPA-10, ACS-16, § II.B.

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

2.5 Sales Forecast for Utility Delivery Service

Utility Delivery service applies to utility customers that take delivery of power over the Utility Delivery segment. *See* Transmission Segmentation Study and Documentation, BP-16-E-BPA-06, § 2.5. Sales forecasts of Utility Delivery service are based on load forecasts, because the charges for the transmission service are based on the customers' loads. BPA forecasts sales for Utility Delivery service using coincident peak POD load forecasts, which are used to develop the rate. The POD load forecast for Utility Delivery service is developed in the same manner as is described in section 2.2.1.2 for the load forecasts for NT service, except that BPA separately calculates the POD load forecast for Utility Delivery customers that take NT service and for the single Utility Delivery customer that takes PTP service. BPA uses the average of the total monthly Utility Delivery POD load forecasts to calculate the Utility Delivery rate, which is discussed in greater detail in section 7.5.1. The annual sales forecasts are shown in table 9. For the Utility Delivery revenue forecast, the

Utility Delivery customers' monthly POD load forecast is multiplied by the proposed Utility Delivery rate for each month in the rate period.

2.6 Revenue Forecasts

The transmission revenue forecasts determine the expected levels of revenue from transmission and ancillary services rates and other sources for the rate period, as indicated in table 12. As discussed above, this study forecasts revenues at current rates and at proposed rates to perform the current revenue test and the revised revenue test. The forecast of revenue at current rates applies the transmission and ancillary services rates placed into effect on October 1, 2013, to the sales forecasts. The forecast of revenue at proposed rates applies the Initial Proposal rates to the sales forecasts. The forecasts are used to test whether the current and proposed rates are sufficient to recover the transmission revenue requirement. The Transmission Revenue Requirement Study further describes the revenue tests.

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

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

A portion of the revenues that BPA forecasts is non-cash revenues due to credits that customers receive against their transmission service charges. (BPA provides these credits in two general circumstances, described below.) The credits (non-cash revenues) are forecast as part of this study and are included in the revenue forecasts discussed above because the transmission services to which they apply are included in the sales forecasts. However, because BPA does not receive the revenue in the form of cash, the credit (and the related interest expense, described below) has a different impact on BPA's revenue requirements and cost recovery than cash revenue. *See* Transmission Revenue Requirement Study, BP-16-E-BPA-08, § 2.3.5.

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

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

The forecasts of transmission credits and related interest expense at current rates and at proposed rates are provided in tables 16.1 and 16.2.

3. REVENUE CREDITS AND ADJUSTMENTS TO THE SEGMENTED REVENUE REQUIREMENTS

Revenue credits and adjustments reflect known costs and revenues that are not accounted for in the Transmission Revenue Requirement Study. To develop the revenue requirements for use in calculating rates, this study allocates the revenue credits among the various segments and then applies these credits and other adjustments to the segmented revenue requirements determined in the Transmission Revenue Requirement Study. It then calculates the net segmented revenue requirements after these credits and adjustments. Finally, the study also corrects an error in the BP-14 rate case in the allocation of costs to the different segments.

3.1 Revenue Credits

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

The revenue credits for fixed-price contracts and fees relate to items such as fiber and wireless leases (in which BPA leases communications capacity that exceeds BPA's operational needs), land leases, reservation and application fees, direct funding of projects and facilities, and O&M charges. The use-of-facilities contracts include agreements such as those governing DSI delivery contracts, under which parties pay for the rights to use specified BPA facilities.

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

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

3.2 Adjustments to the Segmented Revenue Requirements

The study includes certain adjustments to the segmented revenue requirements. These adjustments are not categorized as revenue credits because they do not account for additional revenues. In general, the adjustments allocate (1) individual segment revenues in excess of costs and (2) individual segment costs in excess of revenues. A segment's revenues in excess of costs represent a surplus, which is allocated to the other segments as a credit, reducing the other segments' overall revenue requirements. A segment's costs in excess of revenues represents a cost, which is allocated to the other segments as an additional revenue requirement, increasing the other segments' revenue requirements.

3.2.1 Utility Delivery Adjustment

Section 7.5.1 discusses how BPA calculates the rate for the Delivery Charge for service on Utility Delivery facilities. This calculation includes a limit on the increase in the rate to avoid rate shock. Because of the limit, the Utility Delivery rate does not fully recover Utility Delivery costs. The Utility Delivery adjustment allocates to the other segments Utility Delivery segment costs that are not recovered in Utility Delivery rates. *See* table 3. As with the Eastern Intertie and DSI Delivery adjustments, once the difference between the Utility Delivery segment's adjusted revenue requirement and its revenue recovery has been reduced to zero, no other revenue credits or costs from other segments are allocated to the Utility Delivery segment, since these credits or costs would have to be re-allocated back to other segments.

3.2.2 Eastern Intertie Adjustment

The Eastern Intertie segment includes the Townsend-Garrison transmission (TGT) lines and a portion of the Garrison substation facilities. *See* Transmission Segmentation Study and Documentation, BP-16-E-BPA-06, § 2.4. BPA constructed these facilities under the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), under which BPA provides transmission service for the Colstrip generating facility in Montana. As part of the agreement, the Colstrip Parties (Avista, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy) acquired transmission rights over a portion of the capacity of the Eastern Intertie. BPA receives payments from each party for its share of the Townsend-to-Garrison capacity under the TGT rate. BPA has the right to market any remaining transmission capacity in either direction on the Eastern Intertie.

To determine the net segmented revenue requirement for the Eastern Intertie, the study begins with the gross Eastern Intertie revenue requirement shown in table 1. The study then applies revenue credits and adjustments to the Eastern Intertie segmented revenue requirement.

Table 2 shows the expected revenue credits that apply to the Eastern Intertie segment. The most significant revenue credit relates to revenue from payments to BPA under the Montana Intertie Agreement for rights to transmission service on the TGT transmission lines. These payments are fixed by contract and total $12.4 million annually during the rate period. Since these revenues arise solely through the use of the Eastern Intertie, the study applies the entire amount of this revenue credit to the Eastern Intertie segment. The study also allocates to the Eastern Intertie segment the revenues from sales under the IM rate, since the IM rate applies to PTP transmission service on BPA's capacity share of the Eastern Intertie. Revenues from these sales are forecast to total $0.12 million annually during the rate period. *See* table 3.

The segmented revenue requirement for the Eastern Intertie, including the amount attributable to the correction of the O&M allocation error in the BP-14 rate case, averages $7.95 million annually. *See* table 1. After applying all of the revenue credits and the IM rate revenues to the Eastern Intertie's segmented revenue requirement, the forecast revenues for the Eastern Intertie segment exceed the net segmented revenue requirement on average by $4.81 million annually. *See* table 3. This excess exists primarily because the costs allocated to the Eastern Intertie have been significantly reduced since BPA terminated the Montana Intertie exchange provision in the Montana Intertie Agreement. The exchange provided BPA with 185 MW of east-to-west transmission capacity in Avista's, NorthWestern's, Portland General Electric's, and Puget Sound Energy's ownership shares of the Broadview-to-Townsend line segment in exchange for BPA's assuming a greater-than-proportionate share (in relation to transmission capacity allocations under the Montana Intertie Agreement) of Eastern Intertie costs. Since BPA terminated the exchange, it no longer incurs additional costs associated with the exchange. However, the Colstrip parties' payments to BPA under the Montana Intertie Agreement remain fixed in accordance with the contract as stated above.

The study allocates the $4.81 million in excess revenue from the Eastern Intertie segment to all the other segments proportionally based on net plant investment determined in the Transmission Segmentation Study. This allocation reduces the difference between the Eastern Intertie segment's adjusted revenue requirement and its revenue recovery to zero. *See* table 3. The study then applies the amount of the excess revenue allocated to each segment as an adjustment to reduce the revenue requirement for each segment. Once the difference between the Eastern Intertie segment's adjusted revenue requirement and its revenue recovery has been reduced to zero, no other revenue credits or costs from other segments are allocated to the Eastern Intertie segment, since these credits or costs would have to be re-allocated back to other segments.

3.2.3 DSI Delivery Adjustment

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

However, the study does account for the revenues and costs associated with this segment. The average annual segmented revenue requirement attributable to the DSI Delivery segment, including the amount attributable to the correction of the O&M allocation error in the BP-14 rate case, is $5.64 million. *See* table 1. The Utility Delivery adjustment adds annual costs of $14,000 to the segment, for a total annual revenue requirement of $5.65 million. The revenues generated from sales under the DSI delivery contracts and the other revenue credits allocated to this segment are forecast to average $2.80 million annually during the rate period. *See* table 3. The Eastern Intertie adjustment allocates an annual average of another $20,000 in revenue to this segment, for total annual revenues of $2.821 million. This leaves $2.83 million annually in unrecovered costs associated with the DSI Delivery segment during the rate period.

The DSI Delivery adjustment accounts for recovery of these costs by allocating them to other segments based on the net plant investment ratios from the Transmission Segmentation Study. This allocation reduces the difference between the DSI Delivery segment's adjusted revenue requirement and its revenue recovery to zero. *See* table 3. As with the Eastern Intertie adjustment, once the difference between the DSI Delivery segment's adjusted revenue requirement and its revenue recovery has been reduced to zero, no other revenue credits or costs from other segments are allocated to the DSI Delivery segment, since these credits or costs would have to be re-allocated back to other segments.

3.2.4 Adjustment for NT Redispatch Costs

Under Attachment M to BPA's OATT, Transmission Services initiates redispatch of Federal resources as part of congestion management efforts on the Network. There are three types of redispatch that Transmission Services can request from Power Services to relieve flowgate congestion: Discretionary Redispatch, NT Firm Redispatch, and Emergency Redispatch. Transmission Services requests Discretionary Redispatch to maintain all transmission schedules. Power Services provides this service at its discretion based on real-time operating objectives and constraints. Transmission Services requests NT Firm Redispatch to maintain firm NT schedules, and may do so only after all it has curtailed non-firm Point-to-Point and secondary NT schedules in a sequence consistent with NERC curtailment priority. Power Services must provide NT Firm Redispatch to the extent that it can do so without violating non-power constraints Transmission Services requests Emergency Redispatch if it declares a System Emergency as defined by NERC. Power Services must provide this service even if doing so may violate non-power constraints.

Power Services may respond to requests for redispatch through redispatch of Federal generation, through purchases or sales of energy, or through purchases of transmission. The forecast of costs for Attachment M redispatch is $225,000 per year. *See* Fisher and Fredrickson, BP-16-E-BPA-12, Appendix A, Attachment 3, line 20. These costs are included in the segmented revenue requirement for the Network. *See* Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 2.

Consistent with section 33.3 of BPA's OATT, which provides that NT customers are allocated the redispatch costs associated with firm service to NT load, costs associated with NT Firm Redispatch are allocated to NT customers, because this type of redispatch benefits only NT customers. Accordingly, the study credits the cost of NT Firm Redispatch to the Network segment revenue requirement so that these costs are not included in all Network rates. The costs are then included in the calculation of rates for NT service. *See* table 3, line 31. Section 4 of this study discusses the calculation of the

NT rate. Costs associated with Discretionary Redispatch and Emergency Redispatch are allocated to all Network segment users because Discretionary Redispatch and Emergency Redispatch benefit all Network segment users.

Of the $225,000 per year forecast for Attachment M redispatch, the forecast of costs for NT Firm Redispatch is $160,000 per year. This forecast is based on the historical actual amounts paid by Transmission Services to Power Services in FY 2012–2013 (the most recent rate period for which BPA has actual data). Calculation of the actual revenue Power Services receives from Transmission Services for providing NT Firm Redispatch is based on one of two sources: (1) for redispatch provided from Federal generation, market prices for incrementing and decrementing Federal generation at the time the redispatch is provided, or (2) for redispatch provided by purchases or sales of energy or purchases of transmission, the actual cost to Power Services of the purchase or sale. The forecast of costs for Discretionary Redispatch and Emergency Redispatch are based on this same methodology.

Actual revenues to Power Services for providing NT Firm Redispatch to Transmission Services totaled $528,192 in FY 2012 and $260,116 in FY 2013. Most of the NT Firm Redispatch revenues for FY 2012 ($469,765) was attributable to NT Firm Redispatch events during outages taken to replace wood transmission poles on two transmission lines. BPA does not expect to replace transmission poles in the FY 2016-2017 rate period. Therefore, for purposes of the forecast the associated revenues to Power Services are excluded from the FY 2012 actual revenues, resulting in FY 2012 revenues of $58,427. The average of the FY 2012 revenues ($58,427) and the FY 2013 revenues ($260,116) is $159,272 per year, which was rounded to $160,000 per year.

In addition, BPA's OATT provides that NT customers will make their Network Resources available for redispatch to avoid curtailments to NT service when there are transmission constraints (this type of redispatch is referred to as non-Federal NT redispatch). BPA is evaluating how to implement non-Federal NT redispatch and may implement this type of redispatch during the rate period. However, no non-Federal NT redispatch costs are included in this study. BPA does not have sufficient information regarding the extent and location of future congestion events or the cost to redispatch non-Federal resources to make a forecast for non-Federal NT Redispatch. Therefore, BPA's forecast of the cost of NT Redispatch provided by non-Federal resources is based on historical data. Since BPA has never redispatched non-Federal resources, BPA assumes a cost of $0 per year. Given that historically there have been very few firm congestion events on the BPA system, BPA believes that a $0 cost assumption for non-Federal NT Redispatch is reasonable and does not present significant risk to BPA or its customers.

For the BP-14 proceeding, BPA forecast $80,000 of non-Federal NT Redispatch costs based on anticipated program start-up costs, primarily communications equipment. BPA does not anticipate similar costs during the BP-16 rate period because existing communications equipment will be utilized if non-Federal NT Redispatch is implemented.

3.3 Allocation of Generation Integration Revenues

The Generation Integration segment consists of transmission facilities that integrate Federal resources into BPA's Network. The cost of the Generation Integration segment, including correction of the O&M allocation error and all revenue credits and adjustments, averages $14.77 million annually. *See* table 3, line 36. These costs are assigned to BPA Power Services and recovered through power rates. The payments that Power Services makes to Transmission Services are a revenue credit in the transmission revenue forecast and are applied to the Generation Integration segment.

3.4 Correction of BP-14 O&M Error

An error in the BP-14 rate case in the allocation of O&M costs resulted in a misallocation of costs between the segments. Adams *et al.,* BP-16-E-BPA-13, § 4. In BP-14, the Network and Eastern Intertie segments were allocated more than their correct share of O&M costs; the Generation Integration, Southern Intertie, Utility Delivery, and DSI Delivery segments were allocated less than their correct share. A comparison of the corrected BP-14 average annual revenue requirement for each segment to the published revenue requirement is shown in the table below.

Over/(Under) Allocated Revenue Requirements in the BP-14 Rate Case
(In $000; Rounded to Nearest $1,000)

		Total	Generation Integration	Network	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	SCD
1	Fiscal Year 2014								
2	BP-14 As Published	886,197	9,478	633,671	92,234	9,730	6,174	3,321	131,589
3	Less: BP-14 Corrected	886,197	11,950	624,538	98,118	8,706	7,027	4,270	131,589
4	Equals: Over/(Under) Allocation	0	(2,471)	9,133	(5,884)	1,024	(853)	(949)	0
5	Fiscal Year 2015								
6	BP-14 As Published	934,624	9,832	673,192	95,941	10,111	6,388	3,447	135,712
7	BP-14 Corrected	934,624	12,369	663,816	101,983	9,059	7,264	4,421	135,712
8	Equals: Over/(Under) Allocation	0	(2,537)	9,376	(6,041)	1,051	(876)	(974)	0
9	Rate Period Average								
10	BP-14 As Published	910,410	9,655	653,431	94,088	9,920	6,281	3,384	133,651
11	BP-14 Corrected	910,410	12,159	644,177	100,050	8,883	7,145	4,345	133,651
12	Equals: Over/(Under) Allocation	0	(2,504)	9,255	(5,963)	1,038	(864)	(962)	0

BPA proposes to correct the BP-14 O&M error in BP-16. BPA has adjusted the segmented revenue requirement, for each segment and for each year in the rate period, by the amount over- or under-allocated in BP-14. The adjustments will increase the segmented revenue requirement for those segments that were under-allocated costs in BP-14, and decrease the segmented revenue requirement for those segments that were over-allocated costs in BP-14, by the amount of the under- or over-allocation. *See* table 1, lines 10, 21, and 32. In the case of the Utility Delivery segment, the DSI Delivery segment, and the Eastern Intertie segment, the final revenue requirement does not reflect the full re-allocation because of other adjustments. *See* Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 2.2.

This method of correcting for the error made in BP-14 will not result in a precise, customer-by-customer reversal of the over- and under-charges. Instead, the reversal will correct the error by segment. However, BPA’s current customer base is very similar to the customer base in the BP-14 rate period, minimizing any intergenerational inequity. In addition, correcting the error in the rate period immediately following the BP-14 rate period will minimize any intergenerational inequity.

This page intentionally left blank.

4. NETWORK TRANSMISSION SERVICES

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

In general terms, the study calculates the rates for Network services by taking the net segmented revenue requirement for the Network segment, including the amount attributable to the correction of the O&M allocation error in the BP-14 rate case, subtracting the forecast revenues associated with the transmission portion of FPT service, and allocating a proportionate share of the resulting remaining Network costs to NT, PTP, and IR service. The rates for FPT service are based on certain simplifying assumptions described in section 4.5. The rates for NT, PTP, and IR service are calculated by dividing the costs to be recovered by those services by the NT, PTP, and IR billing determinants, respectively.

4.1 Network Segment Cost Allocation

To calculate the rates for Network services, the study allocates the adjusted Network segment revenue requirement among the various services. The study takes the annual average Network segment revenue requirement from the Transmission Revenue Requirement Study, $683.15 million, and applies an adjustment to account for the BP-14 error, resulting in an adjusted revenue requirement of $673.90 million. *See* table 1. Revenue credits and other adjustments are then applied, resulting in an adjusted Network segment revenue requirement of $654.20 million. *See* § 3 and tables 1 and 3.

As explained in section 4.5, FPT service is provided under contracts that address specific classifications of Network transmission facilities, and FPT rates separately recover a subset of Network costs. Therefore, the study subtracts from the adjusted Network segment revenue requirement $16.05 million in forecast annual revenue attributable to sales of FPT service on the Network. *See* table 7. Subtracting the forecast FPT revenues excludes the costs and revenues attributable to FPT service from the costs allocated among NT, PTP, and IR service, thus ensuring that rates for NT, PTP, and IR service are based only on costs and revenues properly attributable to those services. The result is an annual average cost of $638.17 million to be allocated among NT, PTP, and IR service. *Id*.

The study allocates costs to PTP and IR service based on contract demand and to NT service based on forecast load. The NT load forecast is based on a 12 NCP measure. *See* § 2. The study calculates an allocation percentage for each service based on the ratio of the forecast for each individual service to the total forecast average annual sales for all three services, 35,771 MW. *See* table 7. The allocation percentages for NT, PTP, and IR services are 20.88 percent, 78.38 percent, and 0.74 percent, respectively. *Id.* Multiplying the total adjusted average annual Network revenue requirement of $638.17 million by the sales percentage for each service yields an allocated cost of $133.256 million for NT service, $500.16 million for PTP service, and $4.75 million for IR service. *Id*. The study uses these allocated costs to calculate the rates for NT, PTP, and IR service.

4.2 Network Integration Rate (NT-16)

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

The NT-16 rate schedule identifies a single rate for NT Service and NT Conditional Firm Service under the OATT. Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, NT-16 , § II. The monthly billing factor for the NT-16 rate is the customer's Network load on the hour of the Monthly Transmission System Peak Load for the month (the billing period). *Id.* § III.A.

The NT-16 rate schedule includes a variety of adjustments and references to charges from other rate schedules. The rate schedule includes an SDD available to customers with designated Network Resources that use less than 75 circuit miles of BPA's transmission facilities for delivery to Network Load. *Id.* § IV.D. The SDD is a credit applied to the customer's monthly bill according to the following formula:

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

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

Other charges and provisions in the NT-16 rate schedule include:

- a requirement to purchase Scheduling and Reactive ancillary services
- the Delivery Charge

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

Id. § IV. Section 7 of this study discusses the rate schedule provisions.

To calculate the NT rate, the study begins with the $133.25 million in Network costs allocated to NT service and adds the NT redispatch costs ($160,000 in NT Firm Redispatch of Federal resources costs and $0 in non-Federal NT redispatch costs), which equals total costs of $133.41 million. *See* table 7. Dividing this amount by the NT billing factor of 6,342 MW yields a unit cost of $21,034/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $21.03/kW-year. *Id.* The kW-year unit cost is divided by 12 to yield the rate for NT service, which is $1.753/kW-month. *Id.*

4.3 Point-to-Point Rate (PTP-16)

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

The PTP-16 rate schedule includes rates for long-term service; monthly, weekly, and daily service; and hourly service. 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, PTP-16 , § II. A single rate applies to all long-term firm service and to conditional firm service under the rate schedule. The rate schedule includes two rates for monthly, weekly, and daily service: “Block 1” for the first five days of a reservation, and “Block 2” for the remaining days of the reservation. One hourly rate applies to all hours of a reservation for hourly service. *Id*.

The PTP-16 rate schedule also incorporates a variety of adjustments, charges, notices, and other rate provisions, including:

- a Short-Distance Discount for contract paths less than 75 circuit miles
- a requirement to purchase Scheduling, System Control, and Dispatch Ancillary Service
- the Delivery Charge
- an Unauthorized Increase Charge
- the Reservation Fee
- the Failure to Comply Penalty Charge
- a credit for interruption of daily non-firm service
- notice that BPA will collect capital and related costs of a Direct Assignment Facility under the Advance Funding rate or Use-of-Facilities rate
- notice of BPA’s intent to charge incremental cost rates under specified conditions
- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act.

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

The study calculates the rate for long-term firm PTP service by dividing the Network costs allocated to PTP service, $500.16 million, by the forecast average annual PTP sales of 28,036 MW, yielding a unit cost of $17,840/MW-year. *See* table 7. This amount is then divided by 1,000 to derive a kW-year unit cost of $17.84/kW-year. *Id.*

This kW-year unit cost is divided by 12 to yield the monthly rate for long-term PTP service, $1.487/kW-month. *Id.*

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

In order to account for the greater amount of short-term capacity that is expected to be sold during weekdays and heavy load hours, and to help ensure that the rate for sales during those hours recovers the appropriate amount of costs, the study sets short-term rates at a level higher than a simple pro rata fraction of the long-term rate. It does so by establishing the Block 1 rate for the first five days of short-term daily service based on the costs for a full seven days. The study calculates the Block 1 rate by multiplying the daily PTP unit cost (*i.e.*, the annual rate divided by 365.5, which is the average number of days in each year of the rate period) by a factor of 7/5 (seven total days in the week divided by five weekdays). *See* table 7. The resulting Block 1 rate is $0.068/kW-day. The daily PTP short-term Block 2 rate of $0.049/kW-day is calculated by dividing the unit cost by 365.5 days. *Id.* The PTP daily, weekly, and monthly services are all charged the same block rates.

The study applies a similar factor in the calculation of the rate for hourly service. Since there are 16 heavy load hours each weekday, the hourly rate is set by multiplying the PTP unit cost by an LLH/HLH factor of 24/16 (24 hours per day divided by 16 heavy load hours) and then by the 7/5 daily factor. *Id.* The resulting hourly PTP rate of 4.27 mills/kWh applies to both firm and non-firm hourly sales.

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

4.4 Integration of Resources Rate (IR-16)

As described in section 2, IR contracts integrate multiple resources and transmit non-Federal power over BPA's Network and Delivery facilities to multiple points of delivery on the customer's system. The rate that applies to service under IR agreements includes a single "postage stamp" rate (a rate that does not vary by distance) that combines a monthly demand charge calculated in the same manner as and equal to the demand charge for the PTP rate and the SCD rate. 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, IR-16, § II.A. The IR rate schedule also provides for a charge for GSR.

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

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

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

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

Section 7 of this study explains the rate provisions in detail.

The study calculates the IR rate by dividing the Network costs allocated to IR service, $4.75 million, by the forecast average annual IR sales of 266 MW, yielding a unit cost of $17,840/MW-year. *See* table 7. This amount is divided by 1,000 to derive a kW-year unit cost of $17.84/kW-year. *Id.* This kW-year unit cost is divided by 12 to yield a monthly unit cost of $1.487/kW-month. *Id.*

The costs of providing IR service include the Network transmission costs and the costs of SCD and GSR services, which are the required ancillary services. The IR base rate is calculated by combining the monthly IR service unit cost of $1.487/kW-month with the SCD rate of $0.309/kW-month, for a total IR rate of $1.796/kW-month. The IR-16 rate schedule provides for adding the rate for GSR service to the IR base rate as well. As explained in section 6, however, the GSR rate has been set at zero, so it has no impact on the charges for IR service.

4.5 Formula Power Transmission Rates (FPT-16.1 and FPT-16.3)

The FPT-16.1 rate schedule applies to FPT contracts that allow annual rate adjustments. The FPT-16.3 rate schedule applies to FPT contracts that allow rate changes once every three years.

The FPT rates are generally based on the types of transmission facilities used under a particular FPT contract and the distance the energy is transmitted. The rate schedules include charges for use of facilities that are part of the main grid (that portion of the Network facilities with an operating voltage of 230 kV or more) and for those that are part of the secondary system (that portion of the Network with an operating voltage between 69 kV and 230 kV). 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, FPT-16.1, § II & FPT-16.3, § II. Within the category of facilities designated as "main grid" facilities, there are specific charges for use of main grid interconnection terminals, main grid terminals, and main grid miscellaneous facilities. The secondary system charges are divided into charges for use of secondary system transformation, secondary system intermediate terminals, and secondary system interconnection terminals. FPT-16.1 Rate Schedule § II & FPT-16.3 Rate Schedule § II.

The distance charge has two components: a charge for the distance energy is transmitted over the main grid, and a charge for the distance energy is transmitted over the secondary system. FPT-16.1 Rate Schedule § II & FPT-16.3 Rate Schedule § II. Each FPT contract has a different overall rate per unit of transmission demand based on the facilities used under the contract and the distance energy is transmitted.

The FPT rate also includes the costs associated with SCD and an adjustment for the GSR charge. FPT-16.1 Rate Schedule § II & FPT-16.3 Rate Schedule § II. The rate schedule specifies that customers taking FPT service are subject to the Failure to Comply Penalty

Charge. FPT-16.1 Rate Schedule § IV & FPT-16.3 Rate Schedule § IV. Section 7 discusses these rate schedules.

Only six customers are expected to take FPT service during the rate period, and the sales under the few remaining FPT contracts are forecast to constitute about two percent of BPA's Network revenues. *See* table 4. Given the relatively small effect of the FPT contracts on BPA's revenues, the study relies on certain simplifying assumptions in order to set the FPT-16 rates, instead of a detailed cost analysis of all the categories and subcategories of facilities in the FPT rate schedule. The study assumes that the increase in FPT costs will equal the increase in the sum of the PTP service unit cost (determined in section 4.3) and the rates for the associated ancillary services. The study also assumes that the costs for each of the various FPT rate components (*e.g.*, Main Grid Distance, Main Grid Terminal) will maintain the same proportion to each other as exists in the FPT-14 rates. The facilities used to provide FPT service and associated ancillary services are the same type of facilities used to provide other services over the Network segment. As a result, it is reasonable to assume that their costs accelerate at similar rates and in relation to one another.

The increase in the PTP service unit cost plus the associated ancillary services is 3.5 percent. *See* table 6. As a result, the study sets the FPT-16 rates by increasing each of the current FPT rate components by 3.5 percent. *See* table 11. Any differences in the percentage increase for each individual component are due to rounding the rate for that component.

The forecast revenue from the existing FPT contracts at FY 2014–2015 rates is $18.73 million. *See* table 6. Dividing the forecast revenue at FY 2014–2015 rates by the sales forecast for FY 2016–2017 results in an average FPT rate of $1.585/kW-month. Applying the increase in the unit cost plus the associated ancillary services of 3.5 percent to the revenues at current rates results in an average FPT rate of $1.640/kW-month. The average FPT rate is the denominator for the adjustment for GSR.

Multiplying the sales forecast by the average FPT rate yields a revenue forecast of $19.380 million. The unit cost of the Network component of the rates is 82.8 percent of the sum of the unit cost, the SCD rate, and the GSR rate. *Id*. Applying this percentage to the FPT revenue forecast produces $16.05 million attributable to Network transmission service excluding ancillary services. This amount of revenue is allocated to covering Network costs. The remaining revenues of $3.33 million are attributed to ancillary services and are allocated to cover SCD costs. *See* table 10.1.

This page intentionally left blank.

5. INTERTIE TRANSMISSION SERVICES

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

5.1 Southern Intertie Point-to-Point Rate (IS-16)

The IS-16 rate schedule applies to PTP service on the Southern Intertie. The IS rate schedule includes rates for long-term firm service; monthly, weekly, and daily service; and hourly firm service. A single rate applies to all long-term firm service. Like the PTP-16 rate schedule, the IS-16 rate schedule provides for daily, weekly, and monthly transmission service at daily Block 1 and daily Block 2 rates. One hourly rate applies to all hours of a reservation for hourly service. 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, IS-16, § II.

The IS rate schedule also includes these provisions:

- the requirement to purchase certain ancillary services
- a credit for interruption of daily non-firm service
- the Reservation Fee
- an Unauthorized Increase Charge
- the Failure to Comply Penalty Charge
- notice of BPA’s intent to charge incremental cost rates under specified conditions
- allowance for a rate adjustment pursuant to a FERC order under section 212 of the Federal Power Act

- notice regarding Direct Assignment Facility costs, which are to be collected under the Advance Funding rate or Use-of-Facilities rate.

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

To calculate the IS-16 rates, the study first determines a unit cost for service on the Southern Intertie. The unit cost equals the net segmented revenue requirement for the Southern Intertie segment divided by the forecast sales for the segment. To determine the net segmented revenue requirement, the study begins with the segmented revenue requirement determined in the Transmission Revenue Requirement Study. Revenue credits and other adjustments are then applied to the revenue requirement, including the adjustment to account for the BP-14 error. *See* table 1. Section 3 of the study describes these revenue credits and adjustments.

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

After all revenue credits and adjustments are applied, the average net segmented revenue requirement for the Southern Intertie segment is $99.07 million. *Id.* The projected sales on BPA's portion of the Southern Intertie equal 6,449 MW. *See* table 8. Dividing dollars by megawatts yields annual rate of $15.36/kW-year. *Id.* This annual rate is divided by 12 to determine the IS long-term rate of $1.280/kW-month.

The calculation of the daily and hourly IS-16 rates includes the same adjustment for short-term sales that the study makes for other PTP rates. Section 4.3 explains the adjustment. The daily IS short-term Block 1 rate is calculated by dividing the annual rate, $15.36/kW-year, by 365.5 days/year and multiplying by the LLH/HLH factor of 7/5, which yields $0.059/kW-day. *Id.* The daily IS short-term Block 2 rate is calculated by dividing the annual rate by 365.5 days, yielding $0.042/kW-day. *Id.*

The IS hourly rate applies to both firm and non-firm hourly sales. It is calculated by dividing the annual rate by 8,772 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 and 7/5. The result is a IS-14 hourly rate of 3.68 mills/kWh. *Id.*

5.2 Eastern Intertie (Montana)

The Broadview-to-Garrison intertie facilities, referred to as the Montana Intertie, were built to transmit the output of the Colstrip generating facility, a coal plant in Montana, to the Pacific Northwest. The arrangement for constructing transmission lines and providing transmission service for Colstrip was set forth in the Montana Intertie Agreement. The Colstrip parties to the Montana Intertie Agreement (Avista, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy, or their predecessors) built transmission facilities between Broadview and Townsend, Montana. BPA built the facilities between Townsend and Garrison, which are called the Eastern Intertie. Under the Montana Intertie Agreement, BPA provides transmission service on the Eastern Intertie to the Colstrip parties at the TGT rate. BPA has the right to market any remaining transmission capacity in either direction on the Eastern Intertie.

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

5.2.1 Montana Intertie Rate (IM-16)

The IM-16 rate applies to service on BPA's capacity share of the Eastern Intertie facilities. The IM rate schedule includes rates for long-term firm service; monthly, weekly, and daily service; and hourly firm service. Like the PTP-16 rate schedule, the IM-16 rate schedule provides block rates for monthly, weekly, and daily firm and non-firm service. One hourly rate applies to all hours of a reservation for hourly service. 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, IM-16, § II.

The IM rate schedule also includes these provisions:

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

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

The IM rate is based on BPA's proportionate share of the costs of the Eastern Intertie facilities as identified in the Montana Intertie Agreement. BPA forecasts 16 MW of long-term sales over BPA's capacity during the rate period. *See* table 8.

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

The calculation of the daily and hourly IM-16 rates includes the same adjustment for short-term sales that the study makes for PTP rates. Section 4.3 explains the adjustment. The daily IM-16 short-term Block 1Block 1 rate is set by dividing the IM-16 annual rate by 365.5 days and multiplying by the LLH/HLH factor of 7/5, which yields $0.028/kW-day. *Id.* The daily IM short-term Block 2 rate is calculated by dividing the IM-16 annual rate by 365.5 days, yielding $0.020/kW-day. *Id.*

The IM hourly rate, which applies to both firm and non-firm hourly sales, is calculated by dividing the IM-16 annual rate by 8,772 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 and 7/5. *Id.* The result is an IM-16 hourly rate of 1.72 mills/kWh. *Id.*

5.2.2 Townsend-Garrison Transmission Rate (TGT-16)

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

5.2.3 Eastern Intertie Rate (IE-16)

The IE rate is available to the parties to the Montana Intertie Agreement for non-firm transmission service on the Eastern Intertie. The IE-16 rate is calculated by dividing the annual costs of the Eastern Intertie segment, $7.95 million, by the amount of capacity available to the Colstrip parties on the Eastern Intertie, 1,930 MW, then dividing by 8,772 hours/year, and multiplying by the LLH/HLH factors of 24/16 and 7/5. *See* table 8 and § 4.3. The result is an IE-16 rate of 0.99 mills/kWh.

Under the TGT rate schedule, monthly revenues from any non-firm transactions under the IE-16 and IM-16 rates are deducted from the portion of the total annual costs to be recovered in that month under the TGT rate. The Colstrip parties' portion of the monthly net cost is then allocated to them in accordance with the formula in the TGT rate schedule.

This page intentionally left blank.

6. ANCILLARY AND CONTROL AREA SERVICES

BPA provides ancillary and control area services that are separate from transmission services. This study describes the development of the rates for (1) Scheduling, System Control, and Dispatch Service, and (2) Generation Supplied Reactive Service. The Generation Inputs settlement testimony, Fisher and Fredrickson, BP-16-E-BPA-12, discusses the development of the rates for other ancillary and control area services BPA provides.

6.1 Scheduling, System Control, and Dispatch Service

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

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

SCD service applies to all transmission service, and the equipment that comprises the Ancillary Services segment supports all transmission service. The calculation of the SCD rate starts with the segmented revenue requirement attributable to Scheduling, System Control, and Dispatch, which averages $170.03 million annually over the rate period. *See* table 10.1. The study adjusts the SCD costs by applying revenue credits and other adjustments, including the portion of the FPT revenues allocated to SCD. *See* table 3; table 10; §§ 3 & 4.5. The revenue credits and other adjustments reduce the overall SCD costs to an average of $159.02 million annually over the rate period. *See* table 10.1.

As it does with respect to the calculation of rates for NT, PTP, and IR service on the Network, the study calculates allocation percentages for SCD sales associated with NT (based on the non-coincident peak load forecast), PTP (including PTP service on the Southern Intertie and Montana Intertie), and IR service based on the ratio of the sales forecast for each service to the total forecast average annual SCD sales associated with all three services, 42,830 MW. *See* table 10.1. The allocation percentages for SCD sales associated with NT, PTP, and IR services are 17.72 percent, 81.66 percent, and 0.62 percent, respectively. *Id.* Multiplying the total adjusted average annual SCD revenue requirement of $159.02 million by the sales percentage for each service yields an allocated cost of $28.17 million for NT service, $129.86 million for PTP service, and $0.99 million for IR service. *Id.* The study uses these allocated costs to calculate the rates for SCD service associated with NT, PTP, and IR service.

To calculate the SCD rate for NT service, the study divides the $28.17 million of SCD costs allocated to NT service by the NT billing factor of 6,462 MW (the average monthly NT coincident peak load forecast for the rate period, not considering the Short

Distance Discount). This yields a unit cost of $4,360.09/, which is then divided by 1,000 to derive a kW-year unit cost of $4.36/kW-year. The kW-year unit cost is divided by 12 to yield a monthly SCD for NT service unit cost of $0.363/kW-month. *Id.* The study sets the SCD rate for NT service equal to this monthly unit cost.

The same methodology is used to calculate the SCD rates for PTP, IR, Southern Intertie, and Montana Intertie service. For the SCD rate for PTP service (including PTP service on the Southern Intertie and Montana Intertie), the PTP share of total SCD sales (81.66 percent) is multiplied by the total average annual SCD revenue requirement of $159.02 million, yielding a total PTP service class cost of $129,857.49 million. This value is divided by forecast average annual PTP sales (Long Term and Short Term combined, and not considering the Short Distance Discount) of 34,976 MW, yielding a unit cost of $3,712.77/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $3.71/kW-year. This kW-year unit cost is divided by 12 to yield a monthly SCD for PTP service unit cost of $0.309/kW-month. *Id.*

For the SCD rate for IR service, the IR share of total SCD sales (0.62 percent) is multiplied by the total average annual SCD revenue requirement of $159.02 million, yielding a total IR service class cost of $0.99 million. This value is divided by forecast average annual IR sales of 266 MW, yielding a unit cost of $3,712.77/MW-year, which is then divided by 1,000 to derive a kW-year unit cost of $3.71/kW-year.

This kW-year unit cost is divided by 12 to yield a monthly SCD for IR service unit cost of $0.309/kW-month. *Id*.

The rates for Block 1 daily service and hourly SCD service include the adjustment for short-term sales that the study includes for the rates for every PTP service. Section 4.3 discusses this adjustment. The short-term Block 1 rate of $0.014/kW-day equals the SCD annual unit cost divided by 365.5 days and multiplied by the LLH/HLH factor of 7/5 (seven days divided by five HLH days). *Id.* The Block 2 rate of $0.010/kW-day equals the SCD annual unit cost divided by 365.5 days. *Id.* The study calculates the hourly rate of 0.89 mills/kWh by dividing the annual unit cost by 8,772 hours/year, dividing by 1,000 to convert to mills, and multiplying by the LLH/HLH factors of 24/16 (24 hours/day divided by 16 HLH/day) and 7/5. *Id.*

6.2 Generation Supplied Reactive Service

The GSR rate is set on a quarterly basis pursuant to a formula in the GSR rate schedule. *See* 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, ACS-16, § II.B. As of October 1, 2007, BPA Transmission Services no longer compensates BPA Power Services for generation inputs associated with providing reactive supply and is not required to pay independent power producers for reactive supply inside the deadband. *See Bonneville Power Admin. v. Puget Sound Energy Inc.*, 120 FERC ¶ 61,211 (2007), *reh'g denied*, 125 FERC ¶ 61,273 (2008). Therefore, no costs exist for GSR inside the deadband. BPA is required to pay generators for reactive supply that it requests outside the deadband, pursuant to the generator's FERC-approved rate. BPA does not expect any costs for GSR outside the deadband during the rate period. Therefore, the GSR rate is expected to be zero for the FY 2016–2017 rate period.

This page intentionally left blank.

7. OTHER SERVICES AND PROVISIONS

7.1 Western Electricity Coordinating Council (WECC) and Peak Reliability (Peak) Rate

The WECC and Peak rates recover costs associated with funding the reliability activities of the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), and Peak Reliability (Peak). The WECC rate recovers costs associated with the Electric Reliability Organization (ERO) responsibilities delegated to WECC by NERC. The Peak rate recovers costs associated with the Reliability Coordinator and Interchange Authority functions recently assumed from WECC. The WECC and Peak organizations assign costs to the Balancing Authorities (BAs) they serve based on load in each BA's service area (Balancing Authority Area – BAA). The WECC and Peak costs collected through the WECC and Peak rates are the share of WECC and Peak costs assessed due to customers' load in BPA's BAA.

Total WECC and Peak costs are estimated to average $5.84 million per year for the FY 2016–2017 rate period. These costs are directly assigned to SCD as shown in the Transmission Revenue Requirement Study and are included in the Ancillary Services Segmented Revenue requirement shown on table 1, column I. The forecast $5.84 million per year in WECC and Peak costs are based on 2015 actuals, inflated by 1.6 percent, which is the inflation rate BPA used in the IPR. See Fredrickson *et al.*, BP-16-E-BPA-14, section 8 for more discussion on the costs. Of the total forecast of $5.84 million per year in WECC and Peak costs, $5.06 million of forecast costs ($2.35 million for WECC costs and $2.72 million for Peak costs) are related to customer served load in the BAA. The rates are determined by first removing the WECC and

Peak costs related to customer served load in the BAA from the Ancillary Services segment. *See* table 3, lines 28 and 29. The study then calculates the WECC and Peak rates by dividing the forecast annual average WECC and Peak costs resulting from customer's load in the BAA by the forecast average annual load in the BAA of 52,095,016 Wh. *See* table 10.2, lines 4 and 10. This results in an hourly WECC rate of $0.05 mills/kWh and an hourly Peak rate of $0.05 mills/kWh. *Id.* These rates will only be charged to customers serving load in BPA's BAA. The remaining WECC and Peak costs of $0.77 million ($0.52 million for WECC costs and $0.25 million for Peak costs) remain part of the Ancillary Services revenue requirement and are recovered by all customers paying the SCD rate. The remaining WECC and Peak costs are for unscheduled flow, station service and losses, which are discussed further in Fredrickson *et al.*, BP-16-E-BPA-14, section 8.

7.2 Use-of-Facilities Transmission Rate (UFT-16)

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

The UFT rate schedule includes a formula monthly rate of one-twelfth of the sum of the annual costs of the transmission facilities used by the UFT customer divided by the sum of the transmission demand reserved by the UFT customer. If more than one customer uses given facilities, the costs of the facilities are allocated between the customers based on usage.

BPA adjusts the costs of operating and maintaining the transmission facilities (the numerator in the UFT formula rate) annually. Finally, the UFT rate schedule includes provisions for Ancillary Services and Failure to Comply Penalties.

7.3 Advance Funding Rate (AF-16)

If a customer and BPA agree that the customer should advance fund BPA-owned transmission facilities, the customer will pay BPA the cost of those facilities under the AF-16 rate schedule. Such facilities may include for example, interconnection and resource integration facilities and transmission system upgrades, reinforcements, and replacements. The Advance Funding rate allows BPA to recover costs and prevent stranded costs for facilities that BPA builds under agreements with individual customers. After commercial operation of the facilities, BPA performs a true-up of estimated costs to actual costs and either bills the customer or issues a refund for the difference between the advance payment and the actual costs.

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

This provision is included in the NT, PTP, IS, IM, and ACS rate schedules. After review by FERC, these rate schedules may be modified to satisfy statutory standards for FERC-ordered transmission service. For customers taking transmission service that has not been ordered by FERC, any modifications would be effective only prospectively from the date of the FERC order that grants final approval of the rate schedule for FERC-ordered transmission.

7.5 Delivery Charges

7.5.1 Utility Delivery Charge

The Utility Delivery Charge applies to utility customers that take delivery of power over transmission facilities that are included in the Utility Delivery segment, as defined in the Transmission Segmentation Study. Utility Delivery customers are customers that serve retail load, including as investor-owned utilities, public utility districts, cooperatives, and municipalities.

The annual average segmented revenue requirement for the Utility Delivery segment is $7.18 million. *See* table 1. As described in section 3, the study applies revenue credits and adjustments to this amount to determine the net segmented revenue requirement. The annual average net segmented revenue requirement for the Utility Delivery segment is $6.92 million. *See* table 3.

The study determines an annual unit cost for Utility Delivery service by dividing the $6.92 million revenue requirement by the forecast annual average Utility Delivery sales of 165.12 MW. *See* § 2 & table 9. This results in an annual unit cost of $41.90 /kW-year and a monthly unit cost of $3.492/kW-month. *See* table 9. Setting the Utility Delivery rate equal to the monthly unit cost would result in a 150 percent increase over the current rate of $1.399/kW-month. To avoid the rate shock that would result from such a large increase in the Utility Delivery rate, the study limits the increase in the amount of revenue collected through the Utility Delivery rate to 25 percent. This results in $3.47 million in average annual Utility Delivery revenue and a Utility Delivery charge of $1.749/kW-month. *Id*.

The $3.47 million in average annual revenue expected from the Utility Delivery rate is insufficient to recover the $6.94 million net segmented revenue requirement for the rate period. *Id*. The $3.47 million in average annual Utility Delivery segment costs that are not recovered through the Utility Delivery Charge are allocated to the other transmission segments and recovered through the rates for those segments. *See* § 3.2.1 & table 3.

7.5.2 DSI Delivery Charge

The DSI Delivery Charge applies to direct-service industrial customers that take delivery of power over transmission facilities that are included in the DSI Delivery segment, as defined in the Transmission Segmentation Study. The DSI Delivery Charge is a Use-of-Facility Charge and is determined under sections III.A and B of the UFT-16 rate schedule. See section 7.2 for an explanation of the Use-of-Facility Charge.

7.6 Failure to Comply Penalty Charge

The Failure to Comply Penalty Charge applies when a party fails to comply with BPA's dispatch, curtailment, redispatch, or load shedding orders necessary to maintain system reliability. 2016 Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-E-BPA-10, GRSP § II.B. The charge is the greater of 500 mills/kWh or 150 percent of an hourly energy index in the Pacific Northwest, measured by the number of kilowatthours a party fails to curtail, redispatch, shed load, or change or limit generation in response to a BPA order. In addition, the party is assessed the costs of alternate measures BPA takes to ensure reliability and of any penalties imposed on BPA for violation of any Reliability Standard(s) caused by the party's failure to comply.

7.7 Unauthorized Increase Charge

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

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

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

7.8 Reservation Fee

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

7.9 IR Ratchet Demand

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

This page intentionally left blank.

Table 1
Transmission Revenue Requirements
($000/yr)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Generation		Intertie		Delivery		Ancillary
		Total	Integration	Network	Southern	Eastern	Utility	Industry	Services/1
1	**FY 2016:**								
2	FCRTS Investment Base (Net Plant)	4,288,394	53,924	3,588,419	416,675	76,513	18,787	18,080	115,996
3	Percent of Total		1.3%	83.7%	9.7%	1.8%	0.4%	0.4%	2.7%
4	Operations & Maintenance	455,253	6,509	273,493	40,510	2,038	3,828	2,664	126,209
5	Transmission Acquisition & Ancillary Services	140,767	130	21,445	2,028	80	272	55	116,757
6	Depreciation	239,852	2,804	171,838	25,585	3,005	1,204	1,003	34,413
7	Net Interest Expense	151,344	1,849	126,737	14,895	2,623	644	620	3,977
8	Planned Net Revenues	109,840	1,032	88,995	15,424	1,464	360	346	2,220
9	Subtotal	**1,097,057**	**12,324**	**682,509**	**98,442**	**9,210**	**6,308**	**4,688**	**283,575**
10	Add: BP-14 O&M Error, FY 2014	**(0)**	**2,471**	**(9,133)**	**5,884**	**(1,024)**	**853**	**949**	**-**
11	**Total Transmission Revenue Requirement**	**1,097,057**	**14,795**	**673,376**	**104,326**	**8,186**	**7,161**	**5,637**	**283,575**
12	**FY 2017:**								
13	FCRTS Investment Base (Net Plant)	4,622,380	52,209	3,847,847	487,894	74,061	18,263	17,518	124,588
14	Percent of Total		1.1%	83.2%	10.6%	1.6%	0.4%	0.4%	2.7%
15	Operations & Maintenance	464,803	6,644	279,152	41,348	2,080	3,908	2,720	128,950
16	Transmission Acquisition & Ancillary Services	140,782	126	21,431	2,056	74	271	54	116,772
17	Depreciation	259,210	2,914	184,003	29,739	3,041	1,270	1,048	37,195
18	Net Interest Expense	158,016	1,737	132,007	16,474	2,464	608	583	4,144
19	Planned Net Revenues	86,677	784	67,235	15,140	1,112	274	263	1,870
20	Subtotal	**1,109,488**	**12,204**	**683,828**	**104,756**	**8,771**	**6,330**	**4,667**	**288,932**
21	Add: BP-14 O&M Error, FY 2015	**(0)**	**2,537**	**(9,376)**	**6,041**	**(1,051)**	**876**	**974**	**-**
22	**Total Transmission Revenue Requirement**	**1,109,488**	**14,741**	**674,452**	**110,797**	**7,720**	**7,205**	**5,641**	**288,932**
23	**Annual Average for Rate Period**								
24	FCRTS Investment Base (Net Plant)	4,455,387	53,067	3,718,133	452,285	75,287	18,525	17,799	120,292
25	Percent of Total		1.2%	83.5%	10.2%	1.7%	0.4%	0.4%	2.7%
26	Operations & Maintenance	460,028	6,576	276,323	40,929	2,059	3,868	2,692	127,580
27	Transmission Acquisition & Ancillary Services	140,775	128	21,438	2,042	77	271	54	116,764
28	Depreciation	249,531	2,859	177,921	27,662	3,023	1,237	1,025	35,804
29	Net Interest Expense	154,680	1,793	129,372	15,685	2,543	626	601	4,061
30	Planned Net Revenues	98,259	908	78,115	15,282	1,288	317	304	2,045
31	Subtotal	1,103,272	12,264	683,168	101,599	8,991	6,319	4,677	286,254
32	Add: Average BP-14 O&M Error, FYs 2014/15	(0)	2,504	(9,255)	5,963	(1,038)	864	962	-
33	**Total Transmission Revenue Requirement**	**1,103,272**	**14,768**	**673,914**	**107,562**	**7,953**	**7,183**	**5,639**	**286,254**

/1 Ancillary Service costs not relating to Scheduling, System Control, and Dispatch (SCD) were resolved via settlement.

Table 2
Revenue Credits

	(A) Transmission Revenue Credit	(B) FY 2015 ($000)	(C) FY 2016 ($000)	(D) FY 2017 ($000)	(E) Avg 16/17 ($000/yr)	(F) Growth
1	IS Reservation Fee	-	-	-	-	-
2	UFT Fixed Dollar Amount	4,819	4,819	4,819	4,819	0.0%
3	UFT Variable Service Amt	255	255	255	255	0.0%
4	TGT Firm Demand	12,394	12,394	12,394	12,394	0.0%
5	O&M Non-Federal Facility	640	640	640	640	0.0%
6	O&M Federal Facility	318	318	318	318	0.0%
7	PTP Reservation Fee	325	3,180	3,069	3,124	860.2%
8	CF Reservation Fee	222	74	-	37	-83.3%
9	Failure to Comply Penalty	-	-	-	-	-
10	SINT AC Non Federal O&M	1,695	1,695	1,695	1,695	0.0%
11	SINT AC Non Fed Replacements	-	-	-	-	-
12	Power Factor Penalty Lagging	263	-	-	-	-100.0%
13	Power Factor Penalty Leading	66	-	-	-	-100.0%
14	PFP Lagging Ratchet	2,920	-	-	-	-100.0%
15	PFP Leading Ratchet	854	-	-	-	-100.0%
16	DSI Delivery Charge	2,633	2,633	2,633	2,633	0.0%
17	PCS Wireless Leases	4,475	4,475	4,475	4,475	0.0%
18	PCS Construction	2,810	2,810	2,810	2,810	0.0%
19	PCS Operations & Maintenance	-	-	-	-	-
20	Fiber Leases	8,567	8,567	8,552	8,559	-0.1%
21	Fiber Operations & Maintenance	818	818	812	815	-0.4%
22	Land Use/Lease/Sale	216	216	216	216	0.0%
23	Misc Leases	105	105	104	104	-0.5%
24	Right-Of-Way Lease	79	79	79	79	0.0%
25	COE/BOR Project Revenue	954	954	954	954	0.0%
26	3rd AC Remedial Action Scheme	22	22	22	22	0.0%
27	Transmission Share of IPP	246	246	246	246	0.0%
28	Use of Communication Equipmt	155	153	134	144	-7.5%
29	FPS Real Power Losses	-	-	-	-	-
30	Amort NonFed PNW AC Intertie	3,325	3,325	3,325	3,325	0.0%
31	Transmission Processing Fee	168	168	168	168	0.0%
32	**Total**	**49,344**	**47,946**	**47,719**	**47,833**	-3.1%

Table 2
Revenue Credits

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Credit Segmentation Factors			Generation		Delivery		Intertie		Ancillary
		Basis	Total	Integration	Network	Utility	Industrial	Southern	Eastern	Services
33	IS Reservation Fee	direct	100.00%	-	-	-	-	100.00%	-	-
34	UFT Fixed Dollar Amount	direct	100.00%	0.13%	58.50%	3.51%	-	37.86%	-	-
35	UFT Variable Service Amt	direct	100.00%	0.13%	58.50%	3.51%	-	37.86%	-	-
36	TGT Firm Demand	direct	100.00%	-	-	-	-	-	100.00%	-
37	O&M Non-Federal Facility	direct	100.00%	-	94.17%	0.17%	5.66%	-	-	-
38	O&M Federal Facility	direct	100.00%	-	94.17%	0.17%	5.66%	-	-	-
39	PTP Reservation Fee	network	100.00%	-	100.00%	-	-	-	-	-
40	CF Reservation Fee	network	100.00%	-	100.00%	-	-	-	-	-
41	Failure to Comply Penalty	network	100.00%	-	100.00%	-	-	-	-	-
42	SINT AC Non Federal O&M	southern	100.00%	-	-	-	-	100.00%	-	-
43	SINT AC Non Fed Replacements	southern	100.00%	-	-	-	-	100.00%	-	-
44	Power Factor Penalty Lagging	network	100.00%	-	100.00%	-	-	-	-	-
45	Power Factor Penalty Leading	network	100.00%	-	100.00%	-	-	-	-	-
46	PFP Lagging Ratchet	network	100.00%	-	100.00%	-	-	-	-	-
47	PFP Leading Ratchet	network	100.00%	-	100.00%	-	-	-	-	-
48	DSI Delivery Charge	industry	100.00%	-	-	-	100.00%	-	-	-
49	PCS Wireless Leases	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
50	PCS Construction	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
51	PCS Operations & Maintenance	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
52	Fiber Leases	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
53	Fiber Operations & Maintenance	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
54	Land Use/Lease/Sale	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
55	Misc Leases	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
56	Right-Of-Way Lease	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
57	COE/BOR Project Revenue	direct	100.00%	-	94.17%	0.17%	5.66%	-	-	-
58	3rd AC Remedial Action Sceme	southern	100.00%	-	-	-	-	100.00%	-	-
59	Transmission Share of IPP	network	100.00%	-	100.00%	-	-	-	-	-
60	Use of Communication Equipmt	net plant	100.00%	1.04%	72.55%	0.36%	0.35%	8.83%	1.47%	15.41%
61	FPS Real Power Losses	network	100.00%	-	100.00%	-	-	-	-	-
62	Amort NonFed PNW AC Intertie	southern	100.00%	-	-	-	-	100.00%	-	-
63	Transmission Processing Fee	network	100.00%	-	100.00%	-	-	-	-	-

Table 2
Revenue Credits

	(A) FY 2016 Revenue	(B) Generation Integration ($000)	(C) Network ($000)	(D) Delivery Utility ($000)	(E) Delivery Industrial ($000)	(F) Intertie Southern ($000)	(G) Intertie Eastern ($000)	(H) Ancillary Services ($000)
64	IS Reservation Fee	-	-	-	-	-	-	-
65	UFT Fixed Dollar Amount	6	2,819	169	-	1,824	-	-
66	UFT Variable Service Amt	0	149	9	-	97	-	-
67	TGT Firm Demand	-	-	-	-	-	12,394	-
68	O&M Non-Federal Facility	-	603	1	36	-	-	-
69	O&M Federal Facility	-	299	1	18	-	-	-
70	PTP Reservation Fee	-	3,180	-	-	-	-	-
71	CF Reservation Fee	-	74	-	-	-	-	-
72	Failure to Comply Penalty	-	-	-	-	-	-	-
73	SINT AC Non Federal O&M	-	-	-	-	1,695	-	-
74	SINT AC Non Fed Replacements	-	-	-	-	-	-	-
75	Power Factor Penalty Lagging	-	-	-	-	-	-	-
76	Power Factor Penalty Leading	-	-	-	-	-	-	-
77	PFP Lagging Ratchet	-	-	-	-	-	-	-
78	PFP Leading Ratchet	-	-	-	-	-	-	-
79	DSI Delivery Charge	-	-	-	2,633	-	-	-
80	PCS Wireless Leases	46	3,247	16	16	395	66	690
81	PCS Construction	29	2,039	10	10	248	41	433
82	PCS Operations & Maintenance	-	-	-	-	-	-	-
83	Fiber Leases	89	6,215	31	30	756	126	1,320
84	Fiber Operations & Maintenance	8	593	3	3	72	12	126
85	Land Use/Lease/Sale	2	157	1	1	19	3	33
86	Misc Leases	1	76	0	0	9	2	16
87	Right-Of-Way Lease	1	57	0	0	7	1	12
88	COE/BOR Project Revenue	-	898	2	54	-	-	-
89	3rd AC Remedial Action Sceme	-	-	-	-	22	-	-
90	Transmission Share of IPP	-	246	-	-	-	-	-
91	Use of Communication Equipmt	2	111	1	1	14	2	24
92	FPS Real Power Losses	-	-	-	-	-	-	-
93	Amort NonFed PNW AC Intertie	-	-	-	-	3,325	-	-
94	Transmission Processing Fee	-	168	-	-	-	-	-
95	**Subtotal FY 2016**	**185**	**20,932**	**244**	**2,801**	**8,483**	**12,647**	**2,654**

Table 2
Revenue Credits

	(A) FY 2017 Revenue	(B) Generation Integration	(C) Network	(D) Delivery Utility	(E) Delivery Industrial	(F) Intertie Southern	(G) Intertie Eastern	(H) Ancillary Services
		($000)	($000)	($000)	($000)	($000)	($000)	($000)
96	IS Reservation Fee	-	-	-	-	-	-	-
97	UFT Fixed Dollar Amount	6	2,819	169	-	1,824	-	-
98	UFT Variable Service Amt	0	149	9	-	97	-	-
99	TGT Firm Demand	-	-	-	-	-	12,394	-
100	O&M Non-Federal Facility	-	603	1	36	-	-	-
101	O&M Federal Facility	-	299	1	18	-	-	-
102	PTP Reservation Fee	-	3,069	-	-	-	-	-
103	CF Reservation Fee	-	-	-	-	-	-	-
104	Failure to Comply Penalty	-	-	-	-	-	-	-
105	SINT AC Non Federal O&M	-	-	-	-	1,695	-	-
106	SINT AC Non Fed Replacements	-	-	-	-	-	-	-
107	Power Factor Penalty Lagging	-	-	-	-	-	-	-
108	Power Factor Penalty Leading	-	-	-	-	-	-	-
109	PFP Lagging Ratchet	-	-	-	-	-	-	-
110	PFP Leading Ratchet	-	-	-	-	-	-	-
111	DSI Delivery Charge	-	-	-	2,633	-	-	-
112	PCS Wireless Leases	46	3,247	16	16	395	66	690
113	PCS Construction	29	2,039	10	10	248	41	433
114	PCS Operations & Maintenance	-	-	-	-	-	-	-
115	Fiber Leases	89	6,204	31	30	755	126	1,318
116	Fiber Operations & Maintenance	8	589	3	3	72	12	125
117	Land Use/Lease/Sale	2	157	1	1	19	3	33
118	Misc Leases	1	75	0	0	9	2	16
119	Right-Of-Way Lease	1	57	0	0	7	1	12
120	COE/BOR Project Revenue	-	898	2	54	-	-	-
121	3rd AC Remedial Action Sceme	-	-	-	-	22	-	-
122	Transmission Share of IPP	-	246	-	-	-	-	-
123	Use of Communication Equipmt	1	97	0	0	12	2	21
124	FPS Real Power Losses	-	-	-	-	-	-	-
125	Amort NonFed PNW AC Intertie	-	-	-	-	3,325	-	-
126	Transmission Processing Fee	-	168	-	-	-	-	-
127	**Subtotal FY 2017**	**185**	**20,717**	**243**	**2,801**	**8,479**	**12,646**	**2,648**

Table 3
Segmented Revenue Requirement Adjustments
($000/yr)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Generation		Intertie		Delivery		Ancillary
		Integration	Network	Southern	Eastern	Utility	Industry	Services
1	**FY 2016**							
2	Unadjusted Costs (Table 1).............	14,795	673,376	104,326	8,186	7,161	5,637	283,575
3	Revenue Credits (Table 2)................	-185	-20,932	-8,483	-12,647	-244	-2,801	-2,654
4	WECC Costs 1/………………..........	0	0	0	0	0	0	-2,326
5	Peak Costs 1/……………………....	0	0	0	0	0	0	-2,697
6	IM Tx Revenues.................................	0	0	0	-115	0	0	0
7	NT Federal Redispatch Credit 2/.....	0	-160	0	0	0	0	0
8	NT Nonfederal Redispatch Credit 2/	0	0	0	0	0	0	0
9	Eastern Intertie Adjustment 3/...........	-59	-3,898	-453	4,575	-20	-20	-126
10	Utility Delivery Adjustment 3/.............	44	2,943	342	0	0	15	95
11	Industry Delivery Adjustment 3/.........	37	2,433	283	0	0	-2,831	79
12	**Total**	**14,632**	**653,761**	**96,015**	**0**	**6,897**	**0**	**275,945**
13	**FY 2017**							
14	Unadjusted Costs (Table 1).............	14,741	674,452	110,797	7,720	7,205	5,641	288,932
15	Revenue Credits (Table 2)................	-185	-20,717	-8,479	-12,646	-243	-2,801	-2,648
16	WECC Costs 1/………………..........	0	0	0	0	0	0	-2,363
17	Peak Costs 1/……………………....	0	0	0	0	0	0	-2,741
18	IM Tx Revenues.................................	0	0	0	-115	0	0	0
19	NT Federal Redispatch Credit 2/.....	0	-160	0	0	0	0	0
20	NT Nonfederal Redispatch Credit 2/	0	0	0	0	0	0	0
21	Eastern Intertie Adjustment 3/...........	-58	-4,265	-541	5,041	-20	-19	-138
22	Utility Delivery Adjustment 3/.............	40	2,947	374	0	0	13	95
23	Industry Delivery Adjustment 3/.........	33	2,416	306	0	0	-2,834	78
24	**Total**	**14,571**	**654,673**	**102,458**	**0**	**6,942**	**0**	**281,215**

Table 3
Segmented Revenue Requirement Adjustments
($000/yr)

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Generation Integration	Network	Intertie Southern	Intertie Eastern	Delivery Utility	Delivery Industry	Ancillary Services
25	**Average FY 2016 and FY 2017**							
26	Unadjusted Costs (Table 1).............	14,768	673,914	107,562	7,953	7,183	5,639	286,254
27	Revenue Credits (Table 2)................	-185	-20,825	-8,481	-12,647	-243	-2,801	-2,651
28	WECC Costs 1/………………..........	0	0	0	0	0	0	-2,345
29	Peak Costs 1/…………………….....	0	0	0	0	0	0	-2,719
30	IM Tx Revenues.................................	0	0	0	-115	0	0	0
31	NT Federal Redispatch Credit 2/.....	0	-160	0	0	0	0	0
32	NT Nonfederal Redispatch Credit 2/	0	0	0	0	0	0	0
33	Eastern Intertie Adjustment 3/...........	-58	-4,082	-497	4,808	-20	-20	-132
34	Utility Delivery Adjustment 3/.............	42	2,945	358	0	0	14	95
35	Industry Delivery Adjustment 3/.........	35	2,425	294	0	0	-2,832	78
36	**Total**	**14,602**	**654,217**	**99,236**	**0**	**6,919**	**0**	**278,580**

1/ The WECC/Peak adjustments are for WECC and Peak costs that are 100% assignable to customers' load in BPA's BA.
2/ NT Redispatch Credit adjustments are for NT Redispatch costs that are 100% assignable to NT Service.
3/ Eastern Intertie, Industry Delivery, and Utility Delivery adjustments (cost - revenue) are allocated to the other segments based on table 1 net plant investment percentages.

Table 4
Long-term Transmission Sales

	(A) Transmission Rate Schedule	(B) MWs	(C) Oct	(D) Nov	(E) Dec	(F) Jan	(G) Feb	(H) Mar	(I) Apr	(J) May	(K) Jun	(L) Jul	(M) Aug	(N) Sep	(O) Annual
1	**Network**														
2	**FY 2016**														
3	Formula Power Transmission	m_cd	983	993	1,004	1,004	996	990	986	985	980	982	984	983	**989**
4	Integration of Resources (IR)	m_cd	266	266	266	266	266	266	266	266	266	266	266	266	**266**
5	PTP	m_cd	26,054	26,154	26,204	27,126	27,126	27,126	27,126	27,126	27,126	27,076	27,076	27,076	**26,866**
6	PTP SDD	m_cd	-544	-544	-547	-547	-547	-547	-547	-547	-547	-547	-547	-547	**-546**
7	Point to Point (PTP)	m_cd	25,510	25,610	25,657	26,579	26,579	26,579	26,579	26,579	26,579	26,529	26,529	26,529	**26,320**
8	Point to Point (PTP) w/o SDD	m_cd	26,054	26,154	26,204	27,126	27,126	27,126	27,126	27,126	27,126	27,076	27,076	27,076	**26,866**
9	PTP to Which SCD Charges Do Not Apply	m_cd	-70	-70	-70	-70	-70	-70	-70	-70	-70	-70	-70	-70	**-70**
10	NT SDD EXPECTATION	m_cp	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
11	NT Coincident with Transmission Peak (CP):														
12	Network Load Service	m_cp	5,790	6,927	7,693	7,358	7,035	6,555	5,879	5,541	5,734	6,269	6,247	5,746	**6,398**
13	Network Transmission (NT) (Including SDD)	m_cp	5,670	6,809	7,574	7,239	6,917	6,437	5,759	5,421	5,614	6,149	6,127	5,627	**6,279**
14	Annual peak	a_cp													**7,574**
15	NT Coincident with Customer Peak (NCP):														
16	Network Load Service	m_ncp	6,988	7,954	8,798	8,817	8,379	7,796	7,398	6,806	6,633	7,055	6,955	6,628	**7,517**
17	Network Transmission (NT) (Including SDD)	m_ncp	6,868	7,836	8,680	8,699	8,261	7,678	7,278	6,687	6,513	6,936	6,835	6,508	**7,398**
18	Annual peak	a_ncp													**8,699**
19	**Subtotal FY 2016**		**32,549**	**33,796**	**34,620**	**35,207**	**34,877**	**34,391**	**33,710**	**33,371**	**33,559**	**34,046**	**34,026**	**33,525**	**33,973**
20	**FY 2017**														
21	Formula Power Transmission	m_cd	983	993	1,004	1,004	996	990	986	985	980	949	951	950	**981**
22	Integration of Resources (IR)	m_cd	266	266	266	266	266	266	266	266	266	266	266	266	**266**
23	PTP	m_cd	27,073	27,118	27,097	27,177	27,177	27,177	27,177	27,177	27,177	27,209	27,309	27,309	**27,181**
24	PTP SDD	m_cd	-547	-547	-538	-541	-541	-541	-541	-541	-541	-541	-541	-541	**-541**
25	Point to Point (PTP)	m_cd	26,526	26,571	26,559	26,636	26,636	26,636	26,636	26,636	26,636	26,669	26,769	26,769	**26,640**
26	Point to Point (PTP) w/o SDD	m_cd	27,073	27,118	27,097	27,177	27,177	27,177	27,177	27,177	27,177	27,209	27,309	27,309	**27,181**
27	PTP to Which SCD Charges Do Not Apply	m_cd	-66	-66	-66	-66	-66	-66	-66	-66	-66	-66	-66	-66	**-66**
28	NT SDD EXPECTATION	m_cp	-120	-118	-118	-118	-118	-118	-120	-120	-120	-120	-120	-120	**-119**
29	NT Coincident with Transmission Peak (CP):														
30	Network Load Service	m_cp	5,911	7,060	7,825	7,487	7,183	6,695	6,018	5,675	5,858	6,385	6,358	5,850	**6,525**
31	Network Transmission (NT) (Including SDD)	m_cp	5,791	6,942	7,706	7,369	7,064	6,577	5,898	5,555	5,738	6,266	6,238	5,731	**6,406**
32	Annual peak	a_cp													**7,706**
33	NT Coincident with Customer Peak (NCP):														
34	Network Load Service	m_ncp	7,127	8,091	8,940	8,963	8,545	7,951	7,556	6,955	6,771	7,186	7,080	6,743	**7,659**
35	Network Transmission (NT) (Including SDD)	m_ncp	7,007	7,973	8,821	8,845	8,427	7,833	7,436	6,835	6,651	7,067	6,960	6,623	**7,540**
36	Annual peak	a_ncp													**8,845**
37	**Subtotal FY 2017**		**33,686**	**34,891**	**35,653**	**35,394**	**35,081**	**34,588**	**33,907**	**33,562**	**33,740**	**34,269**	**34,344**	**33,835**	**34,413**

Table 4
Long-term Transmission Sales

	(A) Transmission Rate Schedule	(B) MWs	(C) Oct	(D) Nov	(E) Dec	(F) Jan	(G) Feb	(H) Mar	(I) Apr	(J) May	(K) Jun	(L) Jul	(M) Aug	(N) Sep	(O) Annual
38	**Network Average for Rate Period**														
39	Formula Power Transmission (FPT)	m_cd	983	993	1,004	1,004	996	990	986	985	980	966	968	967	**985**
40	Integration of Resources (IR)	m_cd	266	266	266	266	266	266	266	266	266	266	266	266	**266**
41	Point to Point (PTP) with SDD	m_cd	26,018	26,091	26,108	26,608	26,608	26,608	26,608	26,608	26,608	26,599	26,649	26,649	**26,480**
42	Point to Point (PTP) w/o SDD	m_cd	26,564	26,636	26,651	27,152	27,152	27,152	27,152	27,152	27,152	27,143	27,193	27,193	**27,024**
43	PTP to Which SCD Charges Do Not Apply	m_cd	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	-68	**-68**
44	NT Coincident with Transmission Peak (CP):														
45	Network Load Service	m_cp	5,851	6,994	7,759	7,423	7,109	6,625	5,948	5,608	5,796	6,327	6,303	5,798	**6,462**
46	Network Transmission (NT) (Including SDD)	m_cp	5,731	6,875	7,640	7,304	6,991	6,507	5,829	5,488	5,676	6,207	6,183	5,679	**6,342**
47	Annual peak														**7,640**
48	NT Coincident with Customer Peak (NCP):														
49	Network Load Service	m_ncp	7,058	8,023	8,869	8,890	8,462	7,874	7,477	6,881	6,702	7,121	7,018	6,685	**7,588**
50	Network Transmission (NT) (Including SDD)	m_ncp	6,938	7,904	8,750	8,772	8,344	7,755	7,357	6,761	6,582	7,001	6,898	6,566	**7,469**
51	Annual peak	a_ncp													**8,772**
52	**Subtotal Network**		**33,118**	**34,343**	**35,137**	**35,300**	**34,979**	**34,489**	**33,808**	**33,467**	**33,650**	**34,158**	**34,185**	**33,680**	**34,193**
53	**Southern Intertie**														
54	**FY 2016**														
55	IS	m_cd	6,083	6,056	6,056	6,071	6,071	6,071	6,071	6,071	6,071	6,071	6,071	6,071	**6,070**
56	**FY 2017**														
57	IS	m_cd	6,071	6,071	6,191	6,191	6,191	6,191	6,176	6,176	6,176	6,176	6,176	6,176	**6,163**
58	**Southern Intertie Average for Rate Period**	m_cd	**6,077**	**6,064**	**6,124**	**6,131**	**6,131**	**6,131**	**6,124**	**6,124**	**6,124**	**6,124**	**6,124**	**6,124**	**6,116**
59	**Montana Intertie**														
60	**FY 2016**														
61	Montana Intertie (IM)	m_cd	16	16	16	16	16	16	16	16	16	16	16	16	**16**
62	**FY 2017**														
63	Montana Intertie (IM)	m_cd	16	16	16	16	16	16	16	16	16	16	16	16	**16**
64	**Montana Intertie Average for Rate Period**	m_cd	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**

m_cd = Monthly Contract Demand; m_cp = Monthly Coincidental Peak; a_cp = Annual Coincidental Peak; m_ncp = Monthly Non-Coincidental Peak; a_ncp = Annual Non-Coincidental Peak

Table 5
Short-term Transmission Sales

	(A) Short-term Product	(B) Units	(C) Oct.	(D) Nov.	(E) Dec.	(F) Jan.	(G) Feb.	(H) Mar.	(I) Apr.	(J) May	(K) Jun.	(L) Jul.	(M) Aug.	(N) Sep.	(O) Annual
1	Days in Month		31	30	31	31	29	31	30	31	30	31	31	30	
2	**Network (PTP only short-term)**					2017 only	28								
3	**FY 2016** 1/														
4	Monthly/Weekly/Daily Block1	MW-days	0	0	270	2,675	585	8,475	7,165	19,335	41,475	19,425	455	105	**99,965**
5	Monthly/Weekly/Daily Block2	MW-days	40	35	550	2,575	2,440	3,990	13,790	45,910	51,895	15,900	1,630	65	**138,820**
6	Hourly Firm	MWh	0	0	0	0	0	0	0	0	0	0	0	0	**0**
7	Hourly Nonfirm	MWh	27,720	55,920	209,160	214,152	341,544	263,232	391,944	330,096	831,936	489,480	234,672	18,096	**3,407,952**
8	Monthly/Weekly/Daily Block1	m_cd	0	0	9	86	20	273	239	624	1,383	627	15	4	**273**
9	Monthly/Weekly/Daily Block2	m_cd	1	1	18	83	84	129	460	1,481	1,730	513	53	2	**380**
10	Hourly Firm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
11	Hourly Nonfirm	m_cd	37	78	281	288	491	354	544	444	1,155	658	315	25	**389**
12	**Subtotal FY 2016**	m_cd	**39**	**79**	**308**	**457**	**595**	**756**	**1243**	**2548**	**4268**	**1797**	**383**	**31**	**1,042**
13	**FY 2017** 1/														
14	Monthly/Weekly/Daily Block1	MW-days	0	0	115	2,510	570	8,420	7,110	18,885	40,480	19,325	280	100	**97,795**
15	Monthly/Weekly/Daily Block2	MW-days	20	15	250	2,130	2,375	3,830	13,645	45,200	50,775	15,670	1,000	40	**134,950**
16	Hourly Firm	MWh	0	0	0	0	0	0	0	0	0	0	0	0	**0**
17	Hourly Nonfirm	MWh	27,000	55,320	197,544	197,832	339,696	258,120	386,184	299,304	801,600	476,976	216,120	16,392	**3,272,088**
18	Monthly/Weekly/Daily Block1	m_cd	0	0	4	81	20	272	237	609	1,349	623	9	3	**267**
19	Monthly/Weekly/Daily Block2	m_cd	1	1	8	69	85	124	455	1,458	1,693	505	32	1	**369**
20	Hourly Firm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
21	Hourly Nonfirm	m_cd	36	77	266	266	506	347	536	402	1,113	641	290	23	**375**
22	**Subtotal FY 2017**	m_cd	**37**	**77**	**277**	**416**	**611**	**742**	**1228**	**2470**	**4155**	**1770**	**332**	**27**	**1,012**
23	**Rate Period**														
24	Monthly/Weekly/Daily Block1	m_cd	0	0	6	84	20	273	238	616	1,366	625	12	3	**270**
25	Monthly/Weekly/Daily Block2	m_cd	1	1	13	76	84	126	457	1,470	1,711	509	42	2	**374**
26	Hourly Firm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
27	Hourly Nonfirm	m_cd	37	77	273	277	498	350	540	423	1,134	650	303	24	**382**
28	**Subtotal Rate Period**	m_cd	**38**	**78**	**292**	**436**	**603**	**749**	**1236**	**2509**	**4211**	**1784**	**357**	**29**	**1027**
29	Rate Design 2/	m_cd	78	163	596	774	1159	1243	1925	3221	6006	2748	695	57	**1,555**
30	**Southern Intertie**														
31	**FY 2016** 1/														
32	Monthly/Weekly/Daily Block1	MW-days	30	125	295	135	0	940	1,605	3,115	3,585	6,415	5,775	50	**22,070**
33	Monthly/Weekly/Daily Block2	MW-days	795	860	1,305	945	1,435	2,385	1,865	2,275	2,180	3,030	2,395	145	**19,615**
34	Hourly Firm	MWh	27,384	31,680	29,208	32,544	16,296	52,536	83,880	103,800	189,408	105,144	38,784	114,360	**825,024**
35	Hourly Nonfirm	MWh	0	0	0	0	0	0	0	0	0	0	0	0	**0**
36	Monthly/Weekly/Daily Block1	m_cd	1	4	10	4	0	30	54	100	120	207	186	2	**60**
37	Monthly/Weekly/Daily Block2	m_cd	26	29	42	30	49	77	62	73	73	98	77	5	**53**
38	Hourly Firm	m_cd	37	44	39	44	23	71	117	140	263	141	52	159	**94**
39	Hourly Nonfirm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
40	**Subtotal FY 2016**	m_cd	**63**	**77**	**91**	**79**	**73**	**178**	**232**	**313**	**455**	**446**	**316**	**165**	**207**

Table 5

Short-term Transmission Sales

	(A) Short-term Product	(B) Units	(C) Oct.	(D) Nov.	(E) Dec.	(F) Jan.	(G) Feb.	(H) Mar.	(I) Apr.	(J) May	(K) Jun.	(L) Jul.	(M) Aug.	(N) Sep.	(O) Annual
41	**FY 2017** 1/														
42	Monthly/Weekly/Daily Block1	MW-days	30	130	285	120	0	950	1,600	3,050	3,490	6,405	5,760	50	**21,870**
43	Monthly/Weekly/Daily Block2	MW-days	810	890	1,265	785	1,305	2,415	1,860	2,230	2,120	3,020	2,390	140	**19,230**
44	Hourly Firm	MWh	27,840	32,496	28,224	27,240	14,808	53,136	83,472	101,736	184,008	104,904	38,688	113,112	**809,664**
45	Hourly Nonfirm	MWh	0	0	0	0	0	0	0	0	0	0	0	0	**0**
46	Monthly/Weekly/Daily Block1	m_cd	1	4	9	4	0	31	53	98	116	207	186	2	**59**
47	Monthly/Weekly/Daily Block2	m_cd	26	30	41	25	45	78	62	72	71	97	77	5	**52**
48	Hourly Firm	m_cd	37	45	38	37	21	71	116	137	256	141	52	157	**92**
49	Hourly Nonfirm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
50	**Subtotal FY 2017**	m_cd	**65**	**79**	**88**	**66**	**66**	**180**	**231**	**307**	**443**	**445**	**315**	**163**	**204**
51	**Rate Period**														
52	Monthly/Weekly/Daily Block1	m_cd	1	4	9	4	0	30	53	99	118	207	186	2	**60**
53	Monthly/Weekly/Daily Block2	m_cd	26	29	41	28	47	77	62	73	72	98	77	5	**53**
54	Hourly Firm	m_cd	37	45	39	40	22	71	116	138	259	141	52	158	**93**
55	Hourly Nonfirm	m_cd	0	0	0	0	0	0	0	0	0	0	0	0	**0**
56	**Subtotal Rate Period**	m_cd	**64**	**78**	**89**	**72**	**70**	**179**	**232**	**310**	**449**	**446**	**315**	**164**	**206**
57	Rate Design 2/	m_cd	105	129	136	118	94	269	381	502	781	684	447	339	**332**

1/ Values based on market and streamflow estimates combined with historical trends

2/ Rate Design adjusted MW = 7/5 * Block 1 MW plus Block 2 MW plus 7/5 * 24/16 * hourly MW

m_cd = Monthly Contract Demand (average), i.e. MW-days divided by days in month, MWh divided by hours in month

Table 6
Calculation of Formula Power Transmission Rates

	(A)	(B) Source	(C) Sales	(D) Revenues	(E) Percent	(F) Network Rates
			MegaWatts (MW)	$000/yr		$/kW-mo
1	**Transmission revenues from current rates**					
2	Formula Power Transmission (FPT) sales	Table 4, line 39 (O)	**985**			
3	FY16 FPT Revenues /1	Revenue forecast		18,782		
4	FY17 FPT Revenues /1	Revenue forecast		18,683		
5	Average FPT revenues	(Line 3 + line 4) / 2		18,733		
6	Current unit cost	Line 2 / line 5				1.585
7	Current PTP/IR rate plus Ancillary Services	Table 11, lines 16, 44 and 49 (D)				1.736
8	**Transmission revenues:**					
9	FY 2016-2017 PTP/IR rate plus Ancillary Services	Table 11, lines 16, 44 and 49 (E)				1.796
10	Rate increase (PTP/IR rate + Ancillary)	(Line 9 - line 7) / line 7			3.5%	
11	Unit cost	Line 6 * (1 + line 10)				**1.640**
12	FPT revenues	Line 2 * line 11 * 12		19,380		
13	PTP/IR rate	Table 11, line 16 (E)				1.487
14	Transmission percent of total	Line 13 / line 9			82.8%	
15	Network transmission	Line 14 * line12		**16,046**		
16	Ancillary service percent of total	100% - line 14			17.2%	
17	FPT portion of Scheduling Control & Dispatch	Line 12 - line 15		**3,334**		
18	FPT portion of Generation Supplied Reactive			0		

/1 Based on revenue forecast of FPT contracts active in the FY16/17 time frame

Table 7
Calculation of PTP, IR, and NT Rates

	(A) FY 2016/2017	(B) Source	(C) Costs	(D) Sales	(E) Percentage	(F) Rates	(G) Revenues
1	**Network costs**		$000/Yr	aMW			
2	Segmented Network costs	Table 3, line 36 (C)	654,217				
3	Less: FPT transmission revenues	Table 6, line 15 (D)	16,046				
4	Net costs	Line 2 - line 3	**638,171**				
5	**Network sales (IR, PTP, NT)**						
6	Integration of Resources (IR)	Table 4, line 40 (O)		266			
7	Point to point (PTP) w/o SDD	Table 4, line 42 (O)		27,024			
8	Point to point (PTP) with SDD	Table 4, line 41 (O)		26,480			
9	Network Integration w/o SDD (12 CP Average peak)	Table 4, line 45 (O)		6,462			
10	Network Integration with SDD (= 12CP average peak)	Table 4, line 46 (O)		6,342			
11	Annual peak (1 CP)	Table 4, line 47 (O)		7,640			
12	Annual Noncoincidental Peak (1NCP)	Table 4, line 51 (O)		8,772			
13	Network Integration w/o SDD (12 NCP Average peak)	Table 4, line 49 (O)		7,588			
14	Monthly Noncoincidental Peak (12NCP)	Table 4, line 50 (O)		7,469			
15	Daily Block 1 (day 1 through 5)	Table 5, line 24 (O)		270			
16	Daily Block 2 (day 6 and beyond)	Table 5, line 25 (O)		374			
17	Short-term hourly firm	Table 5, line 26 (O)		0			
18	Short-term hourly non-firm	Table 5, line 27 (O)		382			
19	**Sales used for cost allocation:**						
20	IR Contracts	Line 6		266			
21	NT load (12NCP average peak)	Line 14		7,469			
22	PTP Contracts (w/out SDD)	Line 7		26,480			
23	Daily Block 1 (day 1 through 5)	Line 15 x (7/5)		378			
24	Daily Block 2 (day 6 and beyond)	Line 16		374			
25	Short-term hourly	(Line 17 + line 18) x (7/5) x (24/16)		803			
26	Total cost allocation sales -- Reserved Capacity Contracts	Sum of lines 20 through 25		35,771			
27	**Sales allocation percentages:**						
28	IR contract demand	Line 20		266			
29	Total cost allocation sales	Line 26		35,771			
30	IR Percentage	Line 28 / line 29			**0.74%**		
31	PTP Contract Demand	Sum of lines 22 through 25		28,036			
32	Total cost allocation sales	Line 26		35,771			
33	PTP Percentage	Line 31 / line 32			**78.38%**		
34	NT Load	Line 21		7,469			
35	Total cost allocation sales	Sum of lines 28, 31, and 34		35,771			
36	NT Percentage	Line 34 / line 35			**20.88%**		

Table 7
Calculation of PTP, IR, and NT Rates

	(A) FY 2016/2017	(B) Source	(C) Costs	(D) Sales	(E) Percentage	(F) Rates	(G) Revenues
37	**Application of Revenue Requirements to Products:**						
38	IR Rate Calculation:						
39	Total segment costs	Line 4	638,171				
40	IR cost allocation percentage	Line 30			**0.74%**		
41	Allocated IR costs	Line 39 * line 40	4,746				
42	IR Billing Factor (= IR Contract Demand)	Line 6		266			
43	IR Annual Rate ($/kW-yr)	Line 41 / line 42				17.84	
44	IR Monthly Rate ($/kW-mo)	Line 43 / 12				1.487	
45	PTP Rate Calculation:						
46	Total segment costs	Line 4	638,171				
47	PTP Cost Allocation Percentage	Line 33			**78.38%**		
48	Allocated PTP Costs	Line 46 * line 47	500,173				
49	PTP Billing Factor (= PTP Contract Demand)	Line 8		28,036			
50	PTP Annual Rate ($/kW-yr)	Line 48 / line 49				17.84	
51	PTP Monthly Rate ($/kW-mo)	Line 50 / 12				1.487	
52	Daily block1 ($/kW-day)	Line 50 / (365.5) x (7/5)				0.068	
53	Daily block2 ($/kW-day)	Line 50 / (365.5)				0.049	
54	Hourly (mills/kWh)	Line 50 / (8.772) x (7/5) x (24/16)				4.27	
55	NT Rate Calculation:						
56	Total segment costs	Line 4	638,171				
57	NT Cost allocation percentage	Line 36			**20.88%**		
58	Allocated NT costs	Line 56 * line 57	133,252				
59	NT Federal Redispatch Costs	Table 3, line 25 (C)	160				
60	NT Non-Federal Redispatch Costs	Table 3, line 26 (C)	-				
61	Total NT Costs	Sum of lines 56 through 60	133,412				
62	NT Billing Factor (=NT 12 CP Average Peak Load)	Line 10		6,342			
63	NT Annual Rate ($/kW-yr)	Line 58 / line 59				21.03	
64	NT Monthly Rate ($/kW-mo)	Line 62 / 12				1.753	
65	**Annual revenues at FY 2016-2017 rates**						
66	Integration of Resources (IR)	Line 6 x line 44 x 12					4,747
67	Point-to-point (PTP) LT	Line 8 x line 51 x 12					472,512
68	Network Integration (NT)	Line 10 x line 64 x 12					133,420
69	Short-term Network daily Block 1	Line 15 x line 52 x 365.5					6,717
70	Short-term Network daily Block 2	Line 16 x line 53 x 365.5					6,705
71	Short-term Network hourly	(Line 17 + line 18) x 8.772 x line 54					14,317
72	Subtotal unit cost revenues	Sum of lines 66 through 71					**638,418**

Table 7
Calculation of PTP, IR, and NT Rates

	FY 2016/2017 (A)	(B) Source	(C) Costs	(D) Sales	(E) Percentage	(F) Rates	(G) Revenues
73	**Short distance discount forecast**						
74	NT reduction (credit) from SDD	(Line 9 - line 10) x line 46	2,507				
75	PTP reduction (credit) from SDD	(Line 7 - line 8) x line 50	9,701				
76	Total SDD credit	Line 74 + line 75	**12,207**				

Table 8
Calculation of Intertie Rates

	(A)	(B)	(C)	(D)	(E)
	FY 2016/2017	**Source**	**Costs**	**Sales**	**Rates**
1	**Intertie Costs**		$000/Yr	aMW	
2	Rate Development Costs	Table 3, line 36 (D)	**99,236**		
3	**Southern Intertie Sales**				
4	Long-term agreements	Table 4, line 58 (O)		6,116	
5	Short-term daily Block 1	Table 5, line 52 (O)		60	
6	Short-term daily Block 2	Table 5, line 53 (O)		53	
7	Short-term hourly firm	Table 5, line 54 (O)		93	
8	Short-term hourly non-firm	Table 5, line 55 (O)		-	
9	**Sales used for cost allocation**				
10	Long-term agreements	Line 4		6,116	
11	Daily Block 1 (day 1 through 5)	Line 5 x (7/5)		83	
12	Daily block 2 (day 6 and beyond)	Line 6		53	
13	Short-term hourly	(Line 7 + line 8) x (7/5) x (24/16)		196	
14	Total cost allocation sales	Sum of lines 10 through 13		**6,449**	
15	**IS rate calculation**				
16	Annual ($/kW-yr)	Line 2 / line 14			15.39
17	Monthly ($/kW-mo)	Line 16 / (12)			**1.282**
18	Daily block1 ($/kW-day)	Line 16 / (365.5) x (7/5)			**0.059**
19	Daily block2 ($/kW-day)	Line 16 / (365.5)			**0.042**
20	Hourly (mills/kWh)	Line 16 / (8.772) x (7/5) x (24/16)			**3.68**

Table 8
Calculation of Intertie Rates

	(A)	(B)	(C)	(D)	(E)
	FY 2016/2017	**Source**	**Costs**	**Sales**	**Rates**
21			$000/Yr	aMW	
22	**IM rate calculation**				
23	Eastern Intertie Costs	Montana Intertie Agreement	12,536		
24	IM Sales	Table 4, line 64 (O)		16	
25	TGT Sales	Montana Intertie Agreement		1,730	
26	Total Sales	Line 24 + line 25		1,746	
27	BPA Annual Share of Costs	Line 23 x (line 24 / line 26)	115		
28	Annual ($/kW-yr)	Line 27 / line 24			7.18
29	Monthly ($/kW-mo)	Line 28 / (12)			**0.598**
30	Daily block1 ($/kW-day)	Line 28 / (365.5) x (7/5)			**0.028**
31	Daily block2 ($/kW-day)	Line 28 / (365.5)			**0.020**
32	Hourly (mills/kWh)	Line 28 / (8.772) x (7/5) x (24/16)			**1.72**
33	IM Revenue	Line 24 x line 28		**115**	
34	**IE Rate Calculation**				
35	Eastern Intertie Segment Costs	Table 1, line 33 (F)	**7,953**		
36	Firm Transmission Rights	Montana Intertie Agreement		1,930	
37	Hourly rate (mills/kWh)	Line 35 / line 36 / (8.772) x (7/5) x (24/16)			**0.99**

Table 9
Calculation of Utility Delivery Rate

	(A)	(B)	(C)	(D)	(E)	(F)
	FY 2016/2017	**Units**	**Source**	**Costs**	**Sales**	**Rates**
	Utility Delivery Charge (Full Recovery)					
1	Annual Costs	$000/Yr	Table 3, line 36 (F)	**6,919**		
2	FY16 Billing Factor	m_cp	Sales Forecast		164.78	
3	FY17 Billing Factor	m_cp	Sales Forecast		165.46	
4	Average over Rate Period	m_cp	(Line 2 + line 3) / 2		**165.12**	
5	Calculated Annual Rate	$/kW-yr	Line 1 / line 4			41.90
6	Full Recovery Monthly Rate	$/kW-mo	Line 5 / 12			**3.492**
7						
8	**Calculation of 2016-17 Rate:**					
9	Existing rate ($/kW-month)		Table 11, line 33 (D)		1.399	
10	Times 25%		Initial Proposal		25%	
11	Equals rate increase ($/kW-month)		Line 9 x line 10		0.350	
12	Add: Existing rate ($/kW-month)		Line 9		1.399	
13	Equals: 2016-17 Utility Delivery rate		Line 11 + line 12		1.749	
14	Calculation of Revenue Deficiency:					
15	2016:					
16	Forecast sales (MWs)		Line 2		164.78	
17	Times rate ($/kW-month)		Line 13		1.749	
18	Equals: Monthly revenue ($000)		Line 16 x line 17		288.20	
19	Times 12				12	
20	Equals: Annual revenue ($000)		Line 18 x line 19		3,458.39	
21	Less: 2016 Segment Revenue Requirement ($000)		Table 3, line 12 (F)		6,896.83	
22	Equals Revenue Deficiency, 2016 ($000)		Line 20 - line 21		(3,438.44)	
23	2017:					
24	Forecast sales (MWs)		Line 3		165.46	
25	Times rate ($/kW-month)		Line 13		1.749	
26	Equals: Monthly revenue		Line 24 x line 25		289.40	
27	Times 12				12	
28	Equals: Annual revenue ($000)		Line 26 x line 27		3,472.75	
29	Less: 2017 Segment Revenue Requirement		Table 3, line 24 (F)		6,941.66	
30	Equals Revenue Deficiency, 2017		Line 28 - line 29		(3,468.91)	

Table 10.1
Calculation of Ancillary Services Rates

	(A) FY 2016/2017	(B) Source	(C) FY16	(D) FY17	(E) FY16/17	(F) Sales	(G) Percentage	(H) Rates	(I) Units
			$000/Yr	$000/Yr	$000/Yr	(MW)			
1	**Scheduling, System Control & Dispatch**								
2	Direct O&M	Rev Rqmt	68,038	68,923	68,480				
3	Overheads	Rev Rqmt	58,701	60,573	59,637				
4	Total O&M		126,739	129,495	128,117				
5	Depreciation	Rev Rqmt	34,413	37,195	35,804				
6	Financing costs	Rev Rqmt	3,977	4,144	4,061				
7	Planned net revenue	Rev Rqmt	2,220	1,870	2,045				
8	Total segmented SCD		167,348	172,705	**170,027**				
9	Revenue Credits	Table 3, lines 3 (h) & 15 (H)	-2,654	-2,648	-2,651				
10	WECC Costs	Table 3, lines 4 (h) & 16 (H)	-2,326	-2,363	-2,345				
11	Peak Costs	Table 3, lines 5 (h) & 17 (H)	-2,697	-2,741	-2,719				
12	Eastern Intertie Adjustment	Table 3, lines 9 (h) & 21 (H)	-126	-138	-132				
13	Industry Delivery Adjustment	Table 3, lines 11 (h) & 23 (H)	79	78	78				
14	Utility Delivery Adjustment	Table 3, lines 10 (h) & 22 (H)	95	95	95				
15	Subtotal SCD Costs	Sum of lines 8 through 14	159,718	164,988	**162,353**				
16	FPT revenue for SCD	Table 6, line 17 (D)			3,334				
17	Net SCD Costs	Line 15 - line 16			**159,019**				
18	**Sales Used for Cost Allocation**	-							
19	Reserved Capacity Contracts:	-							
20	IR contract demand	Table 4, line 40 (O)				266			
21	PTP contract demand w/o SDD	Table 4, line 42 (O)				26,956			
22	Network Load	Table 4, line 45 (O)				7,588			
23	Southern Intertie	Table 4, line 58 (O)				6,116			
24	Montana Intertie	Table 4, line 64 (O)				16			
25	PTP Short-term	Table 5, line 29 (O)				1,555			
26	Intertie Short-term	Table 5, line 57 (O)				332			
27	Total Cost Allocation Sales	Sum of lines 20 through 26				42,830			
28	**Sales allocation percentages:**								
29	IR Sales	Line 29				266			
30	Total Cost Allocation Sales	Line 27				42,830			
31	IR Percentage	Line 29 / line 30					0.62%		
32	PTP (Network + Interties) Sales	Line 21 + sum of lines 23 through 27				34,976			
33	Total Cost Allocation Sales	Line 27				42,830			
34	PTP (Network + Intertie) Percentage	Line 32 / line 33					81.66%		
35	NT Sales	Line 22				7,588			
36	Total Cost Allocation Sales	Line 27				42,830			
37	NT Percentage	Line 35 / line 36					17.72%		
38	**IR Rate Calculation:**								
39	Total Segment Costs	Line 17			159,019				
40	IR Cost Allocation Percentage	Line 31					0.62%		
41	Allocated IR Costs	Line 39 x line 40			988				
42	IR Billing Factor (= IR Contract Demand)	Line 20				266			
43	SCD Portion Of Annual Rate For IR Service ($/kW-year)	Line 41 / line 42						3.71	
44	SCD Portion Of Monthly Rate For IR Service ($/W-mo)	Line 43 / 12						0.309	

Table 10.1
Calculation of Ancillary Services Rates

	(A) FY 2016/2017	(B) Source	(C) FY16	(D) FY17	(E) FY16/17	(F) Sales	(G) Percentage	(H) Rates	(I) Units
45	**PTP Rate Calculation:**								
46	Total Segment Costs	Line 17			159,019				
47	PTP (Network + Intertie) Cost Allocation Percentage	Line 34					81.66%		
48	Allocated PTP (Network + Intertie) Costs	Line 46 x line 47			129,858				
49	PTP (Network + Intertie) Billing Factor (= Contract Demand)	Line 32				34,976			
50	SCD for PTP (Network + Intertie) Service Annual Rate ($/kW-yr)	Line 48 / line 49						3.71	
51	SCD for PTP (Network + Intertie) Service Monthly Rate ($/kW-mo)	Line 50 / 12						0.309	
52	Daily block1 ($/kW-day)	Line 50 / (365.5) x (7/5)						0.014	
53	Daily block2 ($/kW-day)	Line 50 / (365.5)						0.010	
54	Hourly (mills/kWh)	Line 50 / (8.772) x (7/5) x (24/16)						0.89	
55	**NT rate calculation:**								
56	Total Segment Costs	Line 17			159,019				
57	NT Cost Allocation Percentage	Line 31					17.72%		
58	Allocated NT Costs	Line 56 x line 57			28,173				
59	NT Billing factor (= NT 12 CP Average Peak Load)	Table 4, line 45 (O)				6,462			
60	SCD Annual Rate for NT Service ($/kW-yr)	Line 58 / line 59						4.36	
61	SCD Monthly Rate for NT Service ($/kW-mo)	Line 60 / 12						0.363	
62	**Rates**								
63	For NT customers:								
64	Annual	Line 60						**4.36**	$/kW-yr
65	Monthly	Line 61						**0.363**	$/kW-mo
66	For PTP customers								
67	Annual	Line 50						**3.71**	$/kW-yr
68	Monthly	Line 51						**0.309**	$/kW-mo
69	Daily Block1 (day 1 through 5)	Line 52						**0.014**	$/kW-day
70	Daily Block2 (day 6 and beyond)	Line 53						**0.010**	$/kW-day
71	Hourly	Line 54						**0.890**	mills/kWh
72	**Generation Supplied Reactive**	No Rqmt	0	0	0			**0**	$/kW-day

/1 See Generation Inputs Study for details about rates associated with Generation Inputs

Table 10.2
Calculation of WECC/Peak Rate

	(A) FY 2016/2017	(B) Units	(C) Source	(D) Costs	(E) Total Load in BPA BAA	(F) Rates
	WECC Charge					
1	Annual Costs	$000/Yr	Forecast	2,345		
2	FY16 Billing Factor	Annual Avg MWh	Sales Forecast		51,323,340	
3	FY17 Billing Factor	Annual Avg MWh	Sales Forecast		52,866,693	
4	Average over Rate Period	Annual Avg MWh	(Line 2 + line 3) / 2		**52,095,016**	
5	Hourly Rate	Mills per kilowatthour	Line 1 / line 4			**0.05**
6	**Peak Charge**					
7	Annual Costs	$000/Yr	Forecast	2,719		
8	FY16 Billing Factor	Annual Avg MWh	Total Load in BPA BAA		51,323,340	
9	FY17 Billing Factor	Annual Avg MWh	Total Load in BPA BAA		52,866,693	
10	Average over Rate Period	Annual Avg MWh	(Line 8 + line 9) / 2		**52,095,016**	
11	Hourly Rate	Mills per kilowatthour	Line 7 / line 10			**0.05**

Table 10.3
Summary of Current and Proposed Rates
(Per Proposed Generation Inputs Settlement Attachment 3)

	(A) Rate	(B) Units	(C) Current 2014 Rates	(D) Proposed 2016 Rates	(E) Percent Change
1	**RFR-16**				
2	Regulation and Frequency Response	mills/kWh	0.12	0.12	0.0%
3	**VERBS-16**				
4	Rate For Wind Committed to 30/60 Scheduling:				
5	Regulation	$/kW-mo	0.08	0.08	0.0%
6	Following	$/kW-mo	0.32	0.32	0.0%
7	Imbalance	$/kW-mo	0.80	0.80	0.0%
8	Total VERBS	$/kW-mo	1.20	1.20	0.0%
9	Rate For Wind Committed to 40/15 Scheduling:				
10	Regulation	$/kW-mo	0.08	0.08	0.0%
11	Following	$/kW-mo	0.32	0.32	0.0%
12	Imbalance	$/kW-mo	0.54	0.54	0.0%
13	Total VERBS	$/kW-mo	0.94	0.94	0.0%
14	Rate For Wind Committed to 30/30 Scheduling:				
15	Regulation	$/kW-mo	0.08	N/A	N/A
16	Following	$/kW-mo	0.32	N/A	N/A
17	Imbalance	$/kW-mo	0.47	N/A	N/A
18	Total VERBS	$/kW-mo	0.87	N/A	N/A
19	Rate For Wind Committed to 30/15 Scheduling:				
20	Regulation	$/kW-mo	0.08	0.08	0.0%
21	Following	$/kW-mo	0.32	0.32	0.0%
22	Imbalance	$/kW-mo	0.33	0.33	0.0%
23	Total VERBS	$/kW-mo	0.73	0.73	0.0%
24	Rate For Wind Committed to Self-Supply:				
25	Regulation	$/kW-mo	0.00		N/A
26	Following	$/kW-mo	0.00		N/A
27	Imbalance	$/kW-mo	0.00		N/A
28	Total VERBS	$/kW-mo	0.00	0.40	N/A

Table 10.3
Summary of Current and Proposed Rates
(Per Proposed Generation Inputs Settlement Attachment 3)

	(A) Rate	(B) Units	(C) Current 2014 Rates	(D) Proposed 2016 Rates	(E) Percent Change
29	Rate For Wind With Uncommitted Scheduling:				
30	Regulation	$/kW-mo	0.08	0.08	0.0%
31	Following	$/kW-mo	0.32	0.32	0.0%
32	Imbalance	$/kW-mo	1.08	1.08	0.0%
33	Total VERBS	$/kW-mo	1.48	1.48	0.0%
34	Rate For Solar:				
35	Regulation	$/kW-mo	0.04	0.04	0.0%
36	Following	$/kW-mo	0.17	0.17	0.0%
37	Imbalance	$/kW-mo	0.00	0.00	N/A
38	Total VERBS	$/kW-mo	0.21	0.21	0.0%
39	**DERBS-16**				
40	Hourly rate *inc*	mills/kWh	18.15	18.15	0.0%
41	Hourly rate *dec*	mills/kWh	3.94	3.94	0.0%
42	**OR-16**				
43	Spinning reserves	mills/kWh	10.86	11.40	5.0%
44	Default rate	mills/kWh	12.49	13.11	5.0%
45	Supplemental reserves	mills/kWh	9.95	10.45	5.0%
46	Default rate	mills/kWh	11.44	12.02	5.1%

Table 11
Summary of FY 2014-2015 and FY 2016-2017 Rates

	(A) Rate	(B) Units	(C) Source for FY 2016-2017 rates	(D) FY 2014-2015 Rates	(E) FY 2016-2017 Rates	(F) Percent Change
1	**FPT-16**					
2	M-G Distance	$/kW-mi-yr	Current Rate * (1 + table 6, line 10)	0.0679	0.0702	3.4%
3	M-G Miscellaneous Facilities	$/kW-yr	Current Rate * (1 + table 6, line 10)	3.87	4.00	3.4%
4	M-G Terminal	$/kW-yr	Current Rate * (1 + table 6, line 10)	0.79	0.82	3.8%
5	M-G Interconnection Terminal	$/kW-yr	Current Rate * (1 + table 6, line 10)	0.71	0.73	2.8%
6	S-S Transformation	$/kW-yr	Current Rate * (1 + table 6, line 10)	7.30	7.55	3.4%
7	S-S Interconnection Terminal	$/kW-yr	Current Rate * (1 + table 6, line 10)	2.00	2.07	3.5%
8	S-S Intermediate Terminal	$/kW-yr	Current Rate * (1 + table 6, line 10)	2.82	2.92	3.5%
9	S-S Distance	$/kW-mi-yr	Current Rate * (1 + table 6, line 10)	0.6676	0.6907	3.5%
10	Average FPT Rate (Revenue/Sales)	$/kW-mo	Table 6, line 11	1.585	1.640	3.5%
11	**IR-16**					
12	Demand	$/kW-mo	Table 7, line 44 + table 10.1, lines 68 + 72	1.736	1.796	3.5%
13	**NT-16**					
14	Demand	$/kW-mo	Table 7, line 64	1.741	1.753	0.7%
15	**PTP-16**					
16	Demand	$/kW-mo	Table 7, line 51	1.479	1.487	0.5%
17	Daily Block 1 (day 1 thru 5)	$/kW-day	Table 7, line 52	0.068	0.068	0.0%
18	Daily Block 2Block 2 (day 6 and beyond)	$/kW-day	Table 7, line 53	0.049	0.049	0.0%
19	Hourly	mills/kWh	Table 7, line 54	4.26	4.27	0.2%
20	**IS-16**					
21	Demand	$/kW-mo	Table 8, line 17	1.128	1.282	13.7%
22	Daily Block 1 (day 1 thru 5)	$/kW-day	Table 8, line 18	0.052	0.059	13.5%
23	Daily Block 2 (day 6 and beyond)	$/kW-day	Table 8, line 19	0.037	0.042	13.5%
24	Hourly	mills/kWh	Table 8, line 20	3.25	3.68	13.2%
25	**IM-16**					
26	Demand	$/kW-mo	Table 8, line 29	0.598	0.598	0.0%
27	Daily Block 1 (day 1 thru 5)	$/kW-day	Table 8, line 30	0.028	0.028	0.0%
28	Daily Block 2 (day 6 and beyond)	$/kW-day	Table 8, line 31	0.020	0.020	0.0%
29	Hourly	mills/kWh	Table 8, line 32	1.72	1.72	0.0%

Table 11
Summary of FY 2014-2015 and FY 2016-2017 Rates

	(A) Rate	(B) Units	(C) Source for FY 2016-2017 rates	(D) FY 2014-2015 Rates	(E) FY 2016-2017 Rates	(F) Percent Change
30	**IE-16**					
31	Eastern Intertie	mills/kWh	Table 8, line 37	1.23	0.99	-19.8%
32	**UD - 16**					
33	Demand	$/kW-mo	Table 9, line 13	1.399	1.749	25.0%
34	**Power Factor Penalty Charge**					
35	Demand -- Lagging	$/kVAr-mo	Rate eliminated	0.28	0.00	-100.0%
36	Demand -- Leading	$/kVAr-mo	Rate eliminated	0.24	0.00	-100.0%
37	**WECC Charge**					
38	Demand	mills/kWh	Table 10.2 , line 5	N/A	0.05	N/A
39	**Peak Charge**					
40	Demand	mills/kWh	Table 10.2 , line 11	N/A	0.05	N/A
41	**SCD-16**					
42	For NT customers	$/kW-mo	Table 10.1, line 65	0.300	0.363	21.0%
43	For PTP customers:					
44	Demand	$/kW-mo	Table 10.1, line 68	0.257	0.309	20.2%
45	Daily Block 1 (day 1 thru 5)	$/kW-day	Table 10.1, line 69	0.012	0.014	16.7%
46	Daily Block 2 (day 6 and beyond)	$/kW-day	Table 10.1, line 70	0.008	0.010	25.0%
47	Hourly	mills/kWh	Table 10.1, line 71	0.74	0.89	20.3%
48	**GSR-16**					
49	Demand	$/kW-mo	Table 10.1, line 72	0.000	0.000	
50	Daily Block 1 (day 1 thru 5)	$/kW-day	Table 10.1, line 0	0.000	0.000	
51	Daily Block 2 (day 6 and beyond)	$/kW-day	Table 10.1, line 0	0.000	0.000	
52	Hourly	mills/kWh	Table 10.1, line 0	0.00	0.00	

Table 12
Revenue at FY 2014-2015 and FY 2016-2017 Rates

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Current FY 2014-2015 Rates		Average	Proposed FY 2016-2017 Rates		Average	Percent
	Service	FY 2016	FY 2017	FY 16&17	FY 2016	FY 2017	FY 16&17	Change
1	**Network Sale Revenues**							
2	FPT 1&3	18,782	18,683	18,733	19,461	19,299	19,380	3.5%
3	IR	5,541	5,541	5,541	5,733	5,733	5,733	3.5%
4	Transmission Ratio from table 6	82.8%						
5	FPT 1&3 Transmission Portion	15,551	15,469	15,510	16,113	15,979	16,046	3.5%
6	IR Transmission Portion	4,588	4,588	4,588	4,747	4,747	4,747	3.5%
7	NT_Base	131,172	133,841	132,506	132,077	134,763	133,420	0.7%
8	NT Ancillary Revenues	23,032	23,492	23,262	27,869	28,425	28,147	21.0%
9	Subtotal NT Sale Revenues	**154,204**	**157,332**	**155,768**	**159,945**	**163,188**	**161,567**	**3.7%**
10	PTP, Long-term	467,131	472,809	469,970	469,658	475,366	472,512	0.5%
11	PTP LT Ancillary Revenues	82,640	83,624	83,132	99,361	100,544	99,952	20.2%
12	PTP, Short-term	28,118	27,202	27,660	28,152	27,234	27,693	0.1%
13	PTP ST Ancillary Revenues	4,832	4,674	4,753	5,821	5,631	5,726	20.5%
14	Subtotal PTP Sale Revenues	**582,721**	**588,309**	**585,515**	**602,992**	**608,776**	**605,884**	**3.5%**
15	Subtotal Network Transmission Revenues	646,560	653,908	650,234	650,746	658,089	654,417	0.6%
16	Percent of total			84.9%			82.6%	
17	Subtotal Network Ancillary Revenues	114,689	115,958	115,323	137,385	138,907	138,146	19.8%
18	Percent of total			15.1%			17.4%	
19	**Total Network Sale Revenues**	**761,249**	**769,866**	**765,557**	**788,131**	**796,996**	**792,563**	**3.5%**
20	**Intertie Sale Revenues**							
21	IM, Long-term	115	115	115	115	115	115	0.0%
22	IM LT Ancillary Revenues	49	49	49	59	59	59	20.2%
23	IS, Long-term	82,157	83,429	82,793	93,373	94,819	94,096	13.7%
24	IS LT Ancillary Revenues	18,718	19,008	18,863	22,506	22,854	22,680	20.2%
25	IS, Short-term	4,555	4,480	4,517	5,162	5,078	5,120	13.3%
26	IS ST Ancillary Revenues	1,032	1,015	1,024	1,239	1,219	1,229	20.1%
27	Subtotal IS Sale Revenues	**106,462**	**107,933**	**107,197**	**122,280**	**123,970**	**123,125**	**14.9%**
28	Subtotal Intertie Transmission Revenues	86,826	88,024	87,425	98,650	100,011	99,331	13.6%
29	Subtotal Intertie Ancillary Revenues	19,800	20,073	19,936	23,804	24,133	23,969	20.2%
30	**Total Intertie Sale Revenues**	**106,626**	**108,097**	**107,362**	**122,454**	**124,144**	**123,299**	**14.8%**

Table 12
Revenue at FY 2014-2015 and FY 2016-2017 Rates

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Current FY 2014-2015 Rates		Average	Proposed FY 2016-2017 Rates		Average	Percent
	Service	FY 2016	FY 2017	FY 16&17	FY 2016	FY 2017	FY 16&17	Change
31	**Ancillary Revenues**							
32	Long-term Scheduling, Control and Dispatch	101,408	102,682	102,045	121,926	123,458	122,692	20.2%
33	Short-term Scheduling, Control and Dispatch	5,864	5,690	5,777	7,060	6,850	6,955	20.4%
34	NT Scheduling, Control and Dispatch	23,032	23,492	23,262	27,869	28,425	28,147	21.0%
35	Subtotal SCD Rate	**130,304**	**131,863**	**131,084**	**156,855**	**158,733**	**157,794**	**20.4%**
36	FPT & IR SCD	4,185	4,168	4,176	4,335	4,307	4,321	3.5%
37	Total SCD Revenue	**134,489**	**136,031**	**135,260**	**161,189**	**163,039**	**162,114**	**19.9%**
38	Regulation and Frequency Response	6,241	6,224	6,233	6,241	6,224	6,233	0.0%
39	VERBS (Wind -- 30/60 Scheduling)	8,006	8,006	8,006	8,006	8,006	8,006	0.0%
40	VERBS (Wind -- 40/15 Scheduling)	-	-	-	-	-	-	N/A
41	VERBS (Wind -- 30/15 Scheduling)	6,675	6,675	6,675	6,675	6,675	6,675	0.0%
42	VERBS (Wind -- Uncommitted Scheduling)	37,296	37,296	37,296	37,296	37,296	37,296	0.0%
43	VERBS (Wind -- Self Supply of Generation Imbalance)	-	-	-	6,672	6,672	6,672	N/A
44	VERBS (Solar)	86	86	86	86	86	86	0.0%
45	DERBS (Inc)	2,059	2,059	2,059	2,059	2,059	2,059	0.0%
46	DERBS (Dec)	391	391	391	391	391	391	0.0%
47	Operating Reserves - Spinning	24,330	24,264	24,297	25,540	25,470	25,505	5.0%
48	Operating Reserves - Supplemental	22,292	22,231	22,261	23,412	23,348	23,380	5.0%
49	Energy Imbalance	-	-	-	-	-	-	N/A
50	Generation Imbalance	-	-	-	-	-	-	N/A
51	**Total Ancillary Revenues**	**241,864**	**243,262**	**242,563**	**277,567**	**279,266**	**278,417**	**14.8%**
52	Subtotal less SCD	107,376	107,231	107,304	116,378	116,227	116,302	8.4%
53	**Delivery**							
54	Utility Delivery	2,766	2,778	2,772	3,458	3,473	3,466	**25.0%**
55	**WECC**							
56	WECC Rate	-	-	-	2,566	2,643	2,605	N/A
57	**Peak**							
58	Peak Rate	-	-	-	2,566	2,643	2,605	N/A
59	**General Transmission Rates Subtotal**	**978,017**	**987,972**	**982,995**	**1,035,554**	**1,046,126**	**1,040,840**	**5.9%**
60	Subtotal less Generation Input Ancillaries	870,641	880,741	875,691	919,176	929,899	924,538	5.6%

Table 12
Revenue at FY 2014-2015 and FY 2016-2017 Rates

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Current FY 2014-2015 Rates		Average	Proposed FY 2016-2017 Rates		Average	Percent
	Service	FY 2016	FY 2017	FY 16&17	FY 2016	FY 2017	FY 16&17	Change
61	**Other Revenues**							
62	IS Reservation Fee	-	-	-	-	-	-	N/A
63	UFT Fixed Dollar Amount	4,819	4,819	4,819	4,819	4,819	4,819	0.0%
64	UFT Variable Service Amt	255	255	255	255	255	255	0.0%
65	TGT Firm Demand	12,394	12,394	12,394	12,394	12,394	12,394	0.0%
66	O&M Non-Federal Facility	640	640	640	640	640	640	0.0%
67	O&M Federal Facility	318	318	318	318	318	318	0.0%
68	PTP Reservation Fee	3,180	3,069	3,124	3,180	3,069	3,124	0.0%
69	CF Reservation Fee	74	-	37	74	-	37	0.0%
70	Failure to Comply Penalty	-	-	-	-	-	-	N/A
71	SINT AC Non Federal O&M	1,695	1,695	1,695	1,695	1,695	1,695	0.0%
72	SINT AC Non Fed Replacements	-	-	-	-	-	-	N/A
73	Power Factor Penalty Lagging	-	-	-	-	-	-	N/A
74	Power Factor Penalty Leading	-	-	-	-	-	-	N/A
75	PFP Lagging Ratchet	-	-	-	-	-	-	N/A
76	PFP Leading Ratchet	-	-	-	-	-	-	N/A
77	DSI Delivery Charge	2,633	2,633	2,633	2,633	2,633	2,633	0.0%
78	PCS Wireless Leases	4,475	4,475	4,475	4,475	4,475	4,475	0.0%
79	PCS Construction	2,810	2,810	2,810	2,810	2,810	2,810	0.0%
80	PCS Operations & Maintenance	-	-	-	-	-	-	N/A
81	Fiber Leases	8,567	8,552	8,559	8,567	8,552	8,559	0.0%
82	Fiber Operations & Maintenance	818	812	815	818	812	815	0.0%
83	Land Use/Lease/Sale	216	216	216	216	216	216	0.0%
84	Misc Leases	105	104	104	105	104	104	0.0%
85	Right-Of-Way Lease	79	79	79	79	79	79	0.0%
86	COE/BOR Project Revenue	954	954	954	954	954	954	0.0%
87	3rd AC Remedial Action Sceme	22	22	22	22	22	22	0.0%
88	Transmission Share of IPP	246	246	246	246	246	246	0.0%
89	Use of Communication Equipmt	153	134	144	153	134	144	0.0%
90	FPS Real Power Losses	-	-	-	-	-	-	N/A
91	Amort NonFed PNW AC Intertie	3,325	3,325	3,325	3,325	3,325	3,325	0.0%
92	Transmission Processing Fee	168	168	168	168	168	168	0.0%
93	Generation Integration BBL	13,152	13,187	13,170	14,632	14,571	14,602	10.9%
94	**Other Revenues Subtotal**	**61,098**	**60,906**	**61,002**	**62,578**	**62,290**	**62,434**	**2.3%**
95	**Total Revenue**	**1,039,115**	**1,048,878**	**1,043,997**	**1,098,132**	**1,108,416**	**1,103,274**	**5.7%**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
1	**FPT One-Year**															
2	**Avista**															
3		DE-MS79-85BP92186														
4			453495	LEGACY	32	32	32	32	32	32	32	32	32	32	32	32
5	**Avista Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**
6																
7	**Douglas**															
8		DE-MS79-80BP90066														
9			(blank)	LEGACY	2	2	2	2	2	2	2	2	2	2	2	2
10	**Douglas Total**				**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
11																
12	**PAC**															
13		DE-MS79-94BP94280														
14			422032	LEGACY	200	200	200	200	200	200	200	200	200	200	200	200
15		DE-MS79-94BP94333														
16			1801200	LEGACY	35	35	35	35	35	35	35	35	35	35	35	35
17			1801201	LEGACY	40	40	40	40	40	40	40	40	40	40	40	40
18			1801202	LEGACY	84	84	84	84	84	84	84	84	84	84	84	84
19			1801203	LEGACY	241	241	241	241	241	241	241	241	241	241	241	241
20			1801397	LEGACY	55	55	55	55	55	55	55	55	55	55	55	55
21			1801398	LEGACY	145	145	145	145	145	145	145	145	145	145	145	145
22	**PAC Total**				**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**
23																
24	**PRC**															
25		DE-MS79-95BP94151														
26			422176	LEGACY	50	50	50	50	50	50	50	50	50	50	50	50
27	**PRC Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
28																
29	**Puget**															
30		DE-MS79-85BP92185														
31			422177	LEGACY	32	32	32	32	32	32	32	32	32	32	32	32
32	**Puget Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**
33																
34	**FPT One-Year Total**				**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**
35																
36	**FPT Three-Year**															
37	**PAC**															
38		14-03-14612														
39			1801204/5	LEGACY	66	76	87	87	79	73	69	68	63	65	67	66
40	**PAC Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**
41																
42	**FPT Three-Year Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
43																
44	**IR**															
45	**Puget**															
46		14-03-45241														
47			1801608	LEGACY	266	266	266	266	266	266	266	266	266	266	266	266
48	**Puget Total**				**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
49																
50	**IR Total**				**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
51																
52	**PTP CONFIRMED**															
53	**Alcoa**															
54		01TX-10630														
55			77208678	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
56			77208409	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
57			77208424	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
58			77208444	RENEWAL	9	9	9	9	9	9	9	9	9	9	9	9
59			77208977	RENEWAL	47	47	47	47	47	47	47	47	47	47	47	47
60			77208984	RENEWAL	15	15	15	15	15	15	15	15	15	15	15	15
61			77208846	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
62			77208855	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
63			77208882	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
64			77208899	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
65			77208633	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
66			77208648	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
67			77208654	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
68			77208559	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
69			77208909	RENEWAL	31	31	31	31	31	31	31	31	31	31	31	31
70			77208934	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
71			77208962	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
72			77208965	RENEWAL	23	23	23	23	23	23	23	23	23	23	23	23
73			77208698	RENEWAL	22	22	22	22	22	22	22	22	22	22	22	22
74			77208709	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
75			77208661	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
76			77208675	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
77	**Alcoa Total**				**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
78																
79	**Arlington**															
80		07TX-12526														
81			72296939	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
82	**Arlington Total**				**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
83				-	-	-	-	-	-	-	-	-	-	-	-	-
84	**Avista**															
85		96MS-96008														
86			1468405	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
87			1468727	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
88			1801278	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
89			1801279	ORIGINAL	147	147	147	147	147	147	147	147	147	147	147	147
90			1801284	ORIGINAL	196	196	196	196	196	196	196	196	196	196	196	196
91			71358397	RECALL	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
92			73613021	ORIGINAL	125	125	125	125	125	125	125	125	125	125	125	125
93			73613033	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
94			77632744	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
95	**Avista Total**				**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**
96																
97	**Benton PUD**															
98		97TX-10041														
99			1800329	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
100			1800338	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
101			1800343	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
102			1800354	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
103			1801465	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
104			71821795	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
105			1800377	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
106			1800379	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
107			1801385	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
108			1800333	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
109			1800364	ORIGINAL	28	28	28	28	28	28	28	28	28	28	28	28
110			71821291	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
111			1800366	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
112			1800373	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
113			1800375	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
114	**Benton PUD Total**				**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**
115																
116	**BPA Power**															
117		02TX-11144														
118			476542	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
119			71706908	REDIRECT	24	24	24	24	24	24	24	24	24	24	24	24
120		96MS-95363														
121			1469289	ORIGINAL	300	300	300	300	300	300	300	300	300	300	300	300
122			1469291	ORIGINAL	88	88	88	88	88	88	88	88	88	88	88	88
123			1470201	ORIGINAL	109	109	109	109	109	109	109	109	109	109	109	109
124			1800939	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
125			1800940	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
126			1800941	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
127			1800942	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
128			1800943	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
129			1800944	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
130			1800945	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
131			1800946	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
132			1800947	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
133			1800948	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
134			1800949	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
135			321890	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90
136			496595	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
137			497792	ORIGINAL	297	297	297	297	297	297	297	-	-	-	-	-
138			497817	ORIGINAL	53	53	53	53	53	53	-	-	-	-	-	-
139			677358	ORIGINAL	116	116	116	116	116	116	-	-	-	-	-	-
140			1800097	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
141			1800100	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
142			1800103	ORIGINAL	11	11	11	11	11	11	11	11	11	11	11	11
143			1800106	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
144			1800109	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
145			1800112	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
146			1800115	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
147			1800118	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
148			1800121	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
149			1800124	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
150			1800127	ORIGINAL	48	48	48	48	48	48	48	48	48	48	48	48
151			1800130	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
152			1800133	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
153			1800137	ORIGINAL	287	287	287	287	287	287	287	287	287	287	287	287
154			72844177	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
155			77078633	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
156			77078601	RENEWAL	17	17	17	17	17	17	17	17	17	17	17	17
157			75100144	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
158		96MS-96060														
159			Multiple	ORIGINAL	667	667	667	667	667	667	667	667	667	667	667	667
160	**BPA Power Total**				**2,512**	**2,512**	**2,512**	**2,512**	**2,512**	**2,512**	**2,343**	**2,046**	**2,046**	**2,046**	**2,046**	**2,046**
161																
162	**Chelan**															
163		01TX-10714														
164			72041989	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
165	**Chelan Total**				**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
166																
167	**Clark**															
168		02TX-11177														
169			73198880	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
170			73198888	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
171			73198896	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
172	**Clark Total**				**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**
173																

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
174	**Clatskanie**															
175		01TX-10649														
176			1321619	ORIGINAL	9	9	9	9	9	9	9	9	9	9	9	9
177			1321623	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
178			1321630	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
179			1321632	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
180			1321634	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
181			1800705	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
182			1800709	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
183			1800717	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
184			1800721	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
185			1800725	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
186			1800729	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
187			1800735	ORIGINAL	14	14	14	14	14	14	14	14	14	14	14	14
188			1800737	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
189			1800740	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
190			1800741	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
191	**Clatskanie Total**				**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**
192																
193	**EDF Renewable**															
194		08TX-13169														
195			78441120	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
196	**EDF Renewable Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
197																
198	**Eurus Comb**															
199		09TX-14147														
200			73185318	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
201			73473061	REDIRECT	62	62	62	62	62	62	62	62	62	62	62	62
202	**Eurus Comb Total**				**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**
203																
204	**Finley Bioenergy**															
205		07TX-12488														
206			71689868	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
207			71915090	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
208	**Finley Bioenergy Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
209																
210	**Franklin County**															
211		97TX-10043														
212			1466591	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
213			1468490	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
214			1469388	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
215			1471445	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
216			1472430	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
217			1801660	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
218			1801665	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
219			1801670	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
220			1801675	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
221			1801680	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
222			1801685	ORIGINAL	22	22	22	22	22	22	22	22	22	22	22	22
223			1801690	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
224			1801695	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
225			1801700	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
226			1801705	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
227			1801710	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
228			71630464	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
229	**Franklin County Total**				**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**
230																
231	**Grant**															
232		01TX-10679														
233			72582664	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
234			74475223	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
235			76084927	REDIRECT	150	150	150	150	150	150	150	150	150	150	150	150
236	**Grant Total**				**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**
237																
238	**Grays Harbor**															
239		96MS-96083														
240			1179595	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
241			1800860	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
242			1800868	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
243			1800869	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
244			1800870	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
245			1800871	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
246			1800872	ORIGINAL	20	20	20	20	20	20	20	20	20	20	20	20
247			1800873	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
248			1800874	ORIGINAL	26	26	26	26	26	26	26	26	26	26	26	26
249			1800875	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
250			1800876	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
251			1800877	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
252			1801266	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
253			1801468	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
254			71316632	REDIRECT	8	8	8	8	8	8	8	8	8	8	8	8
255			72080322	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
256			72080765	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
257	**Grays Harbor Total**				**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**
258																
259	**Hermiston Power**															
260		98TX-10154														
261			1801330	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
262			1801331	ORIGINAL	308	308	308	308	308	308	308	308	308	308	308	308
263	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
264																
265	**Iberdrola**															
266		00TX-10367														
267			73412354	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
268			73412355	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
269			73412487	RENEWAL	3	3	-	-	-	-	-	-	-	-	-	-
270			74371962	RENEWAL	21	21	21	21	21	21	21	21	21	21	21	-
271			74371952	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
272			77895741	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
273			78287943	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
274			78495126	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
275			77079897	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
276			78495051	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
277			78495102	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
278			78577161	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
279			77410610	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
280			76523582	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
281			76523590	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
282			76523592	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
283			77079910	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
284			77410538	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
285			77410542	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
286			75648216	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	-
287			76523573	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
288			75648191	REDIRECT	25	25	-	-	-	-	-	-	-	-	-	-
289			75648180	REDIRECT	50	50	-	-	-	-	-	-	-	-	-	-
290			75648199	REDIRECT	-	-	25	25	25	25	25	25	25	25	25	25
291			75402452	RENEWAL	-	-	50	50	50	50	50	50	50	50	50	50
292			75402568	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
293			75402686	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
294			75648234	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	25
295			77325065	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
296			77325077	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
297			77325082	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
298			77325070	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
299			79556737	RECALL	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
300			78511036	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
301			78511028	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
302			78511047	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
303			78511040	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
304	**Iberdrola Total**				**724**	**724**	**721**	**721**	**721**	**721**	**721**	**721**	**721**	**721**	**721**	**700**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
305				-	-	-	-	-	-	-	-	-	-	-	-	-
306	**Idaho Power Company**															
307		96MS-96108														
308			1801478	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
309			1801479	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
310			1801489	ORIGINAL	53	53	53	53	53	53	53	53	53	53	53	53
311		12TX-15618														
312			77108132	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
313			77108133	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
314		13TX-15768														
315			77443011	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
316			77443034	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
317			77443090	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
318	**Idaho Power Company Total**				**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**
319																
320	**JC-B**															
321		13TX-15809														
322			78685544	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
323	**JC-B Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
324																
325	**Kaiser Alum WA**															
326		11TX-15371														
327			77494335	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
328	**Kaiser Alum WA Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
329																
330	**Klickitat**															
331		97TX-10038														
332			77124569	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
333			77124571	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
334			77124572	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
335			77124573	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
336			77124588	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
337			77124582	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
338			77124583	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
339			77124585	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
340			77124586	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
341			77124575	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
342			77124578	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
343			77124590	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
344			77124591	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
345			77128633	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
346			77124579	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
347			77124581	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
348	**Klickitat Total**				**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**
349																

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
350	**LADWP**															
351		02TX-10944														
352			73033364	RENEWAL	33	33	33	33	33	33	33	-	-	-	-	-
353			73201176	RENEWAL	23	23	23	23	23	23	23	23	-	-	-	-
354			73201205	RENEWAL	20	20	20	20	20	20	20	20	20	20	20	-
355			73201211	RENEWAL	24	24	24	24	24	24	24	24	24	24	-	-
356			78459775	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
357			78459780	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
358			78459765	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
359			78459768	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
360			78459737	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
361			78459759	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
362	**LADWP Total**				**400**	**400**	**400**	**400**	**400**	**400**	**400**	**367**	**344**	**344**	**320**	**300**
363																
364	**Middle Fork**															
365		05TX-11927														
366			1466103	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
367			1469988	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
368	**Middle Fork Total**				**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
369																
370	**Northern Wasco**															
371		09TX-14164														
372			74073792	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
373	**Northern Wasco Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
374																
375	**Okanogan PUD**															
376		01TX-10686														
377			75978650	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
378			75978589	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
379			75978597	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
380			75978607	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
381			75978620	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
382			75978559	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
383			75978566	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
384			75978656	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
385			75978700	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
386			75978643	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
387			75978645	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
388			75978571	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
389			75978577	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
390			75978582	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
391			75978673	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
392			75978693	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
393			75978696	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
394			75978699	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
395			75978636	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
396			75978638	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
397			75978640	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
398			75978586	RENEWAL	13	13	13	13	13	13	13	13	13	13	13	13
399			75978634	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
400			75978524	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
401	**Okanogan PUD Total**				**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**
402																
403	**Outback Solar**															
404		11TX-15513														
405			77028206	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
406			77247649	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
407	**Outback Solar Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
408																
409	**PAC**															
410		04TX-11722														
411			72510730	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
412			72510734	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
413			72513702	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
414			72513705	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
415			72513707	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
416			72604283	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
417			72604325	REDIRECT	80	80	80	80	80	80	80	80	80	80	80	80
418			72604332	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
419			72604342	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
420			73359314	RENEWAL	8	-	-	-	-	-	-	-	-	-	-	-
421			73359317	RENEWAL	8	-	-	-	-	-	-	-	-	-	-	-
422			73359318	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
423			73359319	RENEWAL	146	-	-	-	-	-	-	-	-	-	-	-
424			73359321	RENEWAL	30	-	-	-	-	-	-	-	-	-	-	-
425			73359322	RENEWAL	100	-	-	-	-	-	-	-	-	-	-	-
426			73359325	RENEWAL	85	-	-	-	-	-	-	-	-	-	-	-
427			73359327	RENEWAL	100	-	-	-	-	-	-	-	-	-	-	-
428			73600930	REDIRECT	88	-	-	-	-	-	-	-	-	-	-	-
429			73518379	RENEWAL	144	144	144	144	144	144	144	144	144	144	144	144
430			73518383	RENEWAL	85	85	85	85	85	85	85	85	85	85	85	85
431			73604581	RENEWAL	70	70	70	70	70	70	70	70	70	70	70	70
432			74027888	RENEWAL	222	222	222	222	222	222	222	222	222	222	222	222
433			74027903	RENEWAL	18	18	18	18	18	18	18	18	18	18	18	18
434			74636110	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
435			77322834	RENEWAL	76	76	76	76	76	76	76	76	76	76	76	76
436			77424318	RENEWAL	120	120	120	120	120	120	120	120	120	120	120	120
437			77424414	RENEWAL	190	190	190	190	190	190	190	190	190	190	190	190
438			77810169	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
439			76145322	ORIGINAL	137	137	137	137	137	137	137	137	137	137	137	137
440			76475596	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
441			77322753	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
442			77322823	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
443			76106891	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
444			76182574	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56
445			76191343	ORIGINAL	40	40	40	40	40	40	40	40	40	40	40	40
446			75397855	REDIRECT	100	100	100	100	100	100	100	100	100	100	100	100
447			75503469	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
448			74723497	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
449			77810173	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
450			78385466	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
451			78398821	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
452			77424479	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
453			77520585	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
454			76522087	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
455			76970392	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
456			75766088	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
457			75819074	RENEWAL	28	28	28	28	28	28	28	28	28	28	28	28
458			75841669	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
459			74754673	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
460			75387943	REDIRECT	75	-	-	-	-	-	-	-	-	-	-	-
461			75387944	REDIRECT	10	-	-	-	-	-	-	-	-	-	-	-
462			75503471	REDIRECT	70	70	70	70	70	70	70	70	70	70	70	70
463			78720451	RENEWAL	-	146	146	146	146	146	146	146	146	146	146	146
464			78720471	RENEWAL	-	100	100	100	100	100	100	100	100	100	100	100
465			78720493	RENEWAL	-	100	100	100	100	100	100	100	100	100	100	100
466			78720629	RENEWAL	-	85	85	85	85	85	85	85	85	85	85	85
467			78720424	RENEWAL	-	30	30	30	30	30	30	30	30	30	30	30
468			78721010	RENEWAL	-	88	88	88	88	88	88	88	88	88	88	88
469			78720215	RENEWAL	-	8	8	8	8	8	8	8	8	8	8	8
470			78720311	RENEWAL	-	8	8	8	8	8	8	8	8	8	8	8
471			79191196	REDIRECT	38	38	38	38	38	38	38	38	38	38	38	38
472			79484622	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
473			76382678	REDIRECT	21	21	21	21	21	21	21	21	21	21	21	21
474			78763280	RENEWAL	420	420	420	420	420	420	420	420	420	420	420	420
475			78763246	RENEWAL	70	70	70	70	70	70	70	70	70	70	70	70
476	**PAC Total**				**3,274**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**	**3,189**
477																
478	**Patu Wind Farm**															
479		08TX-13657														
480			72649180	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
481			74128031	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
482	**Patu Wind Farm Total**				**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
483				-	-	-	-	-	-	-	-	-	-	-	-	-
484	**Pend Oreille**															
485		02TX-10875														
486			76277035	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
487			76277045	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
488			76277050	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
489			76277055	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
490			76277060	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
491			76277018	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
492			76277021	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
493			76277025	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
494			76277031	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
495			76277086	RENEWAL	9	9	9	9	9	9	9	9	9	9	9	9
496			76277063	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
497			76277065	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
498			76277067	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
499	**Pend Oreille Total**				**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**
500																
501	**PGE**															
502		96MS-96095														
503			72637681	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
504			72637685	RENEWAL	150	150	150	150	150	150	150	150	-	-	-	-
505			72637689	RENEWAL	250	250	250	250	250	250	250	250	250	250	250	250
506			72637691	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
507			72637692	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
508			73483182	REDIRECT	600	600	600	600	600	600	600	600	-	-	-	-
509		98TX-10174														
510			73970915	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
511		09TX-14507														
512			73540912	RENEWAL	531	531	531	-	-	-	-	-	-	-	-	-
513			73540931	RENEWAL	379	379	379	-	-	-	-	-	-	-	-	-
514			73540935	RENEWAL	250	250	250	-	-	-	-	-	-	-	-	-
515			73540940	RENEWAL	270	270	270	-	-	-	-	-	-	-	-	-
516			73540943	RENEWAL	169	169	169	-	-	-	-	-	-	-	-	-
517			73540964	RENEWAL	131	131	131	-	-	-	-	-	-	-	-	-
518			73540967	RENEWAL	177	177	177	-	-	-	-	-	-	-	-	-
519			73540974	RENEWAL	23	23	23	-	-	-	-	-	-	-	-	-
520			73540978	RENEWAL	27	27	27	-	-	-	-	-	-	-	-	-
521			73540979	RENEWAL	100	100	100	-	-	-	-	-	-	-	-	-
522			73540984	RENEWAL	161	161	161	-	-	-	-	-	-	-	-	-
523			78857909	DEFERRAL	-	45	45	45	45	45	45	45	45	45	45	45
524	**PGE Total**				**3,393**	**3,438**	**3,438**	**1,220**	**1,220**	**1,220**	**1,220**	**1,220**	**470**	**470**	**470**	**470**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
525				-	-	-	-	-	-	-	-	-	-	-	-	-
526	**POTB**															
527		13TX-15849														
528			78391247	DEFERRAL	1	1	1	1	1	1	1	1	1	1	1	1
529	**POTB Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
530																
531	**Powerex**															
532		96MS-96084														
533			1465922	ORIGINAL	230	230	230	230	230	230	230	230	230	230	230	230
534		99TX-10251														
535			74490101	RENEWAL	348	348	348	348	348	348	348	348	348	348	348	348
536			74490405	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
537			75753552	RENEWAL	193	193	193	193	193	193	193	193	193	193	193	193
538			77478534	ORIGINAL	80	80	80	80	80	80	80	80	80	80	80	80
539			77105600	RENEWAL	102	102	102	102	102	102	102	102	102	102	102	102
540			77821635	RENEWAL	125	125	125	125	125	125	125	125	125	125	125	125
541			77821638	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
542	**Powerex Total**				**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**	**1,165**
543																
544	**PPL EnergyPlus**															
545		08TX-13030														
546			72408392	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
547			73063071	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
548	**PPL EnergyPlus Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
549																
550	**PRC**															
551		12TX-15681														
552			76938843	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
553	**PRC Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
554																
555	**Puget**															
556		03TX-11539														
557			73382552	RENEWAL	137	137	137	137	137	-	-	-	-	-	-	-
558		06TX-12195														
559			1466374	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
560			1466379	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
561			1466381	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
562			1466383	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
563			1466385	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
564			1466387	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
565			1466389	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
566			1471793	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
567			1471795	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
568			1471797	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
569			1471799	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
570			1471801	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
571			1471803	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
572			1472838	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
573			1473142	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
574			71365495	RENEWAL	400	400	400	400	400	400	400	400	400	400	400	400
575			71984715	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
576			72813104	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
577			72706601	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
578			72706605	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
579			72706606	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
580			72706608	ORIGINAL	43	43	43	43	43	43	43	43	43	43	43	43
581			73363521	RENEWAL	40	-	-	-	-	-	-	-	-	-	-	-
582			73363525	RENEWAL	40	-	-	-	-	-	-	-	-	-	-	-
583			73363526	RENEWAL	40	-	-	-	-	-	-	-	-	-	-	-
584			73363527	RENEWAL	5	-	-	-	-	-	-	-	-	-	-	-
585			73363530	RENEWAL	55	-	-	-	-	-	-	-	-	-	-	-
586			73363531	RENEWAL	27	-	-	-	-	-	-	-	-	-	-	-
587			73363533	RENEWAL	27	-	-	-	-	-	-	-	-	-	-	-
588			73363535	RENEWAL	27	-	-	-	-	-	-	-	-	-	-	-
589			73363536	RENEWAL	3	-	-	-	-	-	-	-	-	-	-	-
590			73363537	RENEWAL	36	-	-	-	-	-	-	-	-	-	-	-
591			73363546	RENEWAL	5	-	-	-	-	-	-	-	-	-	-	-
592			71616447	RENEWAL	235	235	-	-	-	-	-	-	-	-	-	-
593			75012886	RENEWAL	23	23	23	23	23	23	23	23	23	23	23	23
594			77286231	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
595			77286242	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
596			77855235	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
597			76213396	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
598			76213399	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
599			76213403	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
600			77286223	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
601			73395728	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
602			76041858	RENEWAL	94	94	94	94	94	94	94	94	94	94	94	94
603			76041860	RENEWAL	160	160	160	160	160	160	160	160	160	160	160	160
604			76213391	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
605			72886051	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
606			72886075	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
607			72886101	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
608			78527177	RENEWAL	263	263	263	263	263	263	263	263	263	263	263	263
609			78527185	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
610			78527191	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
611			78510701	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
612			78510722	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
613			78510643	RENEWAL	115	115	115	115	115	115	115	115	115	115	115	115
614			77286250	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
615			77913795	RENEWAL	35	35	35	35	35	35	35	35	35	35	35	35

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
616			77913798	RENEWAL	27	27	27	27	27	27	27	27	27	27	27	27
617			76213405	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
618			76213407	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
619			76041854	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
620			72885921	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
621			72885963	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
622			72886013	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
623			78527159	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
624			78527166	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
625			78527170	RENEWAL	150	150	150	150	150	150	150	150	150	150	150	150
626			78903869	RENEWAL	-	-	169	169	169	169	169	169	169	169	169	169
627			78262265	ORIGINAL	-	1	1	1	1	1	1	1	1	1	1	1
628	**Puget Total**				**4,303**	**3,999**	**3,933**	**3,933**	**3,933**	**3,796**	**3,796**	**3,796**	**3,796**	**3,796**	**3,796**	**3,796**
629																
630	**SC Edison**															
631		10TX-14641														
632			75978147	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
633			75978181	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
634			75978191	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
635			75978193	ORIGINAL	120	120	120	120	120	120	120	120	120	120	120	120
636			76252310	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
637			76252318	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
638			76252286	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
639			76252295	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
640			76252305	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
641	**SC Edison Total**				**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**
642																
643	**Seattle**															
644		96MS-96018														
645			1800082	ORIGINAL	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023
646			1800521	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
647			1800522	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
648			1800523	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
649			1800524	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
650			1800525	ORIGINAL	46	46	46	46	46	46	46	46	46	46	46	46
651			1800526	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52
652			1800527	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
653			1800528	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
654			1800529	ORIGINAL	83	83	83	83	83	83	83	83	83	83	83	83
655			1800530	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
656			1800531	ORIGINAL	158	158	158	158	158	158	158	158	158	158	158	158
657			1801314	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
658			1801315	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
659			1801316	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
660			1801356	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
661			1801399	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
662			1801474	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
663			1801824	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
664			71852108	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
665			73833947	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
666	**Seattle Total**				**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**
667																
668	**Sherman County**															
669		04TX-11833														
670			79276006	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
671			79276016	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
672			79276024	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
673			79276106	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
674			79276111	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
675			76179605	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
676			76179608	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
677			76179591	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
678			76179597	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
679			76179603	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
680	**Sherman County Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
681																
682	**SMUD**															
683		02TX-11128														
684			77703370	DEFERRAL	30	30	30	30	30	30	30	30	30	30	30	30
685			79132005	DEFERRAL	-	-	-	30	30	30	30	30	30	30	30	30
686	**SMUD Total**				**30**	**30**	**30**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**
687																
688	**Snohomish**															
689		96MS-96092														
690			1800028	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
691			1800080	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
692			1801078	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
693			1801079	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
694			1801080	ORIGINAL	38	38	38	38	38	38	38	38	38	38	38	38
695			1801081	ORIGINAL	39	39	39	39	39	39	39	39	39	39	39	39
696			1801082	ORIGINAL	72	72	72	72	72	72	72	72	72	72	72	72
697			1801083	ORIGINAL	81	81	81	81	81	81	81	81	81	81	81	81
698			1801084	ORIGINAL	85	85	85	85	85	85	85	85	85	85	85	85
699			1801085	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
700			1801086	ORIGINAL	156	156	156	156	156	156	156	156	156	156	156	156
701			1801087	ORIGINAL	247	247	247	247	247	247	247	247	247	247	247	247
702			1801163	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
703			1801362	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
704			1801451	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
705			1801500	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
706			1801823	ORIGINAL	131	131	131	131	131	131	131	131	131	131	131	131

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
707			72566153	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
708			72566175	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
709			72566200	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
710			72673396	RECALL	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
711			72673445	RECALL	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
712			73240353	ORIGINAL	51	51	51	51	51	51	51	51	51	51	51	51
713			72150853	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
714			72150855	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
715			73240347	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
716			72150858	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
717	**Snohomish Total**				**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**
718																
719	**Tacoma Power**															
720		98TX-10103														
721			1472937	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
722			1800542	ORIGINAL	19	19	19	19	19	19	19	19	19	19	19	19
723			1800543	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
724			1800544	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
725			1800545	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
726			1800546	ORIGINAL	44	44	44	44	44	44	44	44	44	44	44	44
727			1800547	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52
728			1800548	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
729			1800550	ORIGINAL	82	82	82	82	82	82	82	82	82	82	82	82
730			1800551	ORIGINAL	99	99	99	99	99	99	99	99	99	99	99	99
731			1800565	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
732			1800566	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
733			1800567	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
734			1800568	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
735			1800569	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
736			1800570	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
737			1800571	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
738			1800572	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
739			1800573	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
740			1800574	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
741			1801317	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
742			1801318	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
743			1801319	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
744			1801501	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
745			71851948	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
746			71851958	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
747			71984719	REDIRECT	48	48	48	48	48	48	48	48	48	48	48	48
748			71984725	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
749			72032784	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
750			75108469	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
751			75108338	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
752			75724017	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
753			75108487	RECALL	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
754			75108431	RECALL	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
755			1800552	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
756			1800549	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
757	**Tacoma Power Total**				**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**
758																
759	**TEMUS**															
760		98TX-10172														
761			73918209	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
762			73918184	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
763			78976989	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
764	**TEMUS Total**				**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**
765																
766	**Turlock Irrigation**															
767		00TX-10344														
768			77517818	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
769			77517830	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
770	**Turlock Irrigation Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
771																
772	**Wheat Field Wind**															
773		08TX-13610														
774			72458260	ORIGINAL	97	97	97	97	97	97	97	97	97	97	97	97
775	**Wheat Field Wind Total**				**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
776																
777	**PTP CONFIRMED Total**				**25,216**	**24,872**	**24,803**	**22,615**	**22,615**	**22,478**	**22,309**	**21,979**	**21,206**	**21,206**	**21,182**	**21,141**
778																
779	**PTP CONFIRMED NO SCD**															
780	**L & M**															
781		06TX-12244														
782			72873760	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
783	**L & M Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
784																
785	**Lower Valley**															
786		08TX-13671														
787			75429714	ORIGINAL	2	2	2	2	2	2	2	-	-	-	-	-
788			78866292	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
789	**Lower Valley Total**				**4**	**4**	**4**	**4**	**4**	**4**	**4**	**2**	**2**	**2**	**2**	**2**
790																
791	**Raft River Energy**															
792		07TX-12449														
793			1471160	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
794	**Raft River Energy Total**				**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status / Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
795																
796	**UAMPS**															
797		11TX-15512														
798			77309382	ORIGINAL	53	53	53	53	53	53	53	53	53	53	53	53
799	**UAMPS Total**				**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**
800																
801	**PTP CONFIRMED NO SCD Total**				**70**	**70**	**70**	**70**	**70**	**70**	**70**	**68**	**68**	**68**	**68**	**68**
802																
803	**PTP SDD**															
804	**Avista**															
805		96MS-96008														
806			77632744	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
807	**Avista Total**				**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**
808																
809	**Franklin County**															
810		97TX-10043														
811			1472430	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
812	**Franklin County Total**				**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**
813																
814	**Grant**															
815		01TX-10679														
816			76084927	SDD	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
817	**Grant Total**				**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**	**(60)**
818																
819	**Iberdrola**															
820		00TX-10367														
821			78287943	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
822			77079897	SDD	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
823			77410610	SDD	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
824			77079910	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
825			77410538	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
826			77410542	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
827	**Iberdrola Total**				**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**
828																
829	**Idaho Power Company**															
830		12TX-15618														
831			77108132	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
832			77108133	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
833	**Idaho Power Company Total**				**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**
834																
835	**JC-B**															
836		13TX-15809														
837			78685544	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
838	**JC-B Total**				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
839				-	-	-	-	-	-	-	-	-	-	-	-	-
840	**Middle Fork**															
841		05TX-11927														
842			1466103	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
843			1469988	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
844	**Middle Fork Total**				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
845																
846	**PAC**															
847		04TX-11722														
848			73518379	SDD	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)
849			73518383	SDD	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)	(22)
850			77424318	SDD	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
851			77424414	SDD	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
852			77810169	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
853			77322823	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
854			76191343	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
855			74723497	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
856			77810173	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
857			77424479	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
858			76522087	SDD	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
859	**PAC Total**				**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**	**(248)**
860																
861	**POTB**															
862		13TX-15849														
863			78391247	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
864	**POTB Total**				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
865																
866	**Puget**															
867		03TX-11539														
868			73382552	SDD	(37)	(37)	(37)	(37)	(37)	-	-	-	-	-	-	-
869	**Puget Total**				**(37)**	**(37)**	**(37)**	**(37)**	**(37)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
870																
871	**Raft River Energy**															
872		07TX-12449														
873			1471160	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
874	**Raft River Energy Total**				**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
875				-	-	-	-	-	-	-	-	-	-	-	-	-
876	**SC Edison**															
877		10TX-14641														
878			75978147	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
879			75978181	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
880			75978191	SDD	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
881			75978193	SDD	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
882			76252310	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
883			76252318	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
884			76252286	SDD	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
885			76252295	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
886			76252305	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
887	**SC Edison Total**				**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**
888																
889	**SMUD**															
890		02TX-11128														
891			77703370	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
892	**SMUD Total**				**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**
893																
894	**UAMPS**															
895		11TX-15512														
896			77309382	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
897	**UAMPS Total**				**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**
898																
899	**PTP SDD Total**				**(543.9)**	**(543.9)**	**(543.9)**	**(543.9)**	**(543.9)**	**(507.0)**	**(507.0)**	**(507.0)**	**(507.0)**	**(507.0)**	**(507.0)**	**(507.0)**
900																
901	**PTP CF CONFIRMED**															
902	**Iberdrola**															
903		00TX-10367														
904			78738359	DEFERRAL	-	-	50	50	50	50	50	50	50	50	50	50
905	**Iberdrola Total**				**-**	**-**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
906																
907	**LADWP**															
908		02TX-10944														
909			74228809	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
910	**LADWP Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
911																
912	**PAC**															
913		04TX-11722														
914			77119166	REDIRECT	88	88	88	88	88	88	88	88	88	88	88	88
915			75846783	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
916	**PAC Total**				**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
	PGE															
		09TX-14507														
			78858032	DEFERRAL	-	100	100	100	100	100	100	100	100	100	100	100
	PGE Total				**-**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
	Puget															
		06TX-12195														
			74856145	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
			76945532	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
			77565922	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
			77565931	ORIGINAL	40	40	40	40	40	40	40	40	40	40	40	40
	Puget Total				**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
	Shell Energy															
		00TX-10286														
			74928222	DEFERRAL	125	125	125	125	125	125	125	125	125	125	125	125
	Shell Energy Total				**125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**	**125**
	TEMUS															
		98TX-10172														
			74623822	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
			74623837	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
			79132196	RECALL	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
	TEMUS Total				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
PTP CF CONFIRMED Total					**473**	**573**	**623**	**623**	**623**	**623**	**623**	**623**	**623**	**623**	**623**	**623**
PTP EXPECTATION																
				ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
				RENEWAL	150	455	455	2,673	2,673	2,810	2,979	3,309	3,782	3,782	3,806	3,847
				DEFERRAL (RECALL)	(205)	(250)	(250)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(220)
PTP EXPECTATION Total					**(5)**	**255**	**255**	**2,443**	**2,443**	**2,580**	**2,749**	**3,079**	**3,552**	**3,552**	**3,576**	**3,677**
PTP SDD EXPECTATION																
					-	-	-	-	-	(37)	(37)	(37)	(37)	(37)	(37)	(37)
PTP SDD EXPECTATION Total					**-**	**-**	**-**	**-**	**-**	**(37)**	**(37)**	**(37)**	**(37)**	**(37)**	**(37)**	**(37)**
PTP CF EXPECTATION																
				DEFERRAL (RECALL)	-	(100)	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150)
PTP CF EXPECTATION Total					**-**	**(100)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**	**(150)**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status / Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
962	**IS CONFIRMED**															
963	**BPA Power**															
964		96MS-95363														
965			321873	ORIGINAL	700	700	700	700	700	700	700	700	700	700	700	700
966			321874	ORIGINAL	300	300	300	300	300	300	300	300	300	300	300	300
967			483765	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
968		96MS-96060														
969			71383980	ORIGINAL	60	15	15	15	15	15	15	60	60	60	60	60
970	**BPA Power Total**				**1,110**	**1,065**	**1,065**	**1,065**	**1,065**	**1,065**	**1,065**	**1,110**	**1,110**	**1,110**	**1,110**	**1,110**
971																
972	**Exelon Generation**															
973		02TX-11265														
974			78225336	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
975			78225361	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
976			78225363	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
977			78221134	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
978	**Exelon Generation Total**				**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**
979																
980	**Hermiston Power**															
981		98TX-10154														
982			1800038	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
983			1801359	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
984			449487	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
985			449491	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
986			449493	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
987	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
988																
989	**Iberdrola**															
990		00TX-10367														
991			71678981	ORIGINAL	280	280	280	280	280	280	280	280	280	280	280	280
992			1466882	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
993			72288164	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
994			72552123	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
995			72511486	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
996			72511519	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
997			76659161	RENEWAL	95	95	95	95	95	95	95	95	95	95	95	95
998			72511528	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
999			76303736	RENEWAL	47	47	47	47	47	47	47	47	47	47	47	47
1000			77719214	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
1001			78154124	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
1002			75596535	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
1003			76303714	RENEWAL	180	180	180	180	180	180	180	180	180	180	180	180
1004			76303727	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
1005			76303731	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
1006	**Iberdrola Total**				**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**	**1,002**

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
1007																
1008	**Morgan Stanley**															
1009		97TX-10031														
1010			1470598	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
1011			1467616	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
1012			1470752	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
1013			1470754	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
1014			72398097	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
1015			72921329	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
1016			1470382	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
1017			1470384	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
1018			1470386	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
1019			1470388	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
1020			73014940	ORIGINAL	73	73	73	73	73	73	73	73	73	73	73	73
1021			75533108	RENEWAL	46	46	46	46	46	46	46	46	46	46	46	46
1022			73016708	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
1023			72496577	ORIGINAL	74	74	74	74	74	74	74	74	74	74	74	74
1024			72496624	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
1025			78676775	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
1026	**Morgan Stanley Total**				**574**	**574**	**574**	**574**	**574**	**574**	**574**	**574**	**574**	**574**	**574**	**574**
1027																
1028	**PAC**															
1029		DE-MS79-94BP94280														
1030			422159	ORIGINAL	200	200	200	-	-	-	-	-	-	-	-	-
1031		DE-MS79-94BP94285														
1032			427472	ORIGINAL	93	93	93	93	93	93	93	93	93	93	93	93
1033			866020	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
1034	**PAC Total**				**364**	**364**	**364**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**
1035																
1036	**Powerex**															
1037		99TX-10251														
1038			72617596	RENEWAL	49	49	49	-	-	-	-	-	-	-	-	-
1039			72617597	RENEWAL	51	51	51	-	-	-	-	-	-	-	-	-
1040			72668081	RENEWAL	150	150	150	-	-	-	-	-	-	-	-	-
1041			72742268	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
1042			78710047	RENEWAL	200	200	200	200	200	200	200	200	200	200	200	200
1043			79100585	RENEWAL	-	-	-	51	51	51	51	51	51	51	51	51
1044			79100588	RENEWAL	-	-	-	150	150	150	150	150	150	150	150	150
1045			79461718	RENEWAL	-	-	-	49	49	49	49	49	49	49	49	49
1046			75322538	RENEWAL	24	24	24	24	24	24	24	24	24	24	24	24
1047			75322539	RENEWAL	15	15	15	15	15	15	15	15	15	15	15	15
1048			75322540	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
1049			77502254	RENEWAL	357	357	357	357	357	357	357	357	357	357	357	357
1050			77543772	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
1051			77543773	RENEWAL	286	286	286	286	286	286	286	286	286	286	286	286
1052			77543781	RENEWAL	650	650	650	650	650	650	650	650	650	650	650	650

Table 13.1
2015 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
					-	-	-	-	-	-	-	-	-	-	-	-	-
1053				75796869	ORIGINAL	100	100	100	100	100	100	100	100	100	100	-	-
1054				75796829	ORIGINAL	100	100	100	100	100	100	100	100	100	100	-	-
1055		**Powerex Total**				**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**2,085**	**1,885**	**1,885**
1056																	
1057		**Shell Energy**															
1058			00TX-10286														
1059				72429308	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
1060				72513298	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
1061				72513308	RENEWAL	20	20	20	20	20	20	20	20	20	20	20	20
1062				72513313	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
1063		**Shell Energy Total**				**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**
1064																	
1065		**TEMUS**															
1066			98TX-10172														
1067				77302316	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
1068				78163252	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
1069		**TEMUS Total**				**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**
1070																	
1071	**IS CONFIRMED Total**					**6,083**	**6,038**	**6,038**	**5,838**	**5,838**	**5,838**	**5,838**	**5,883**	**5,883**	**5,883**	**5,683**	**5,683**
1072																	
1073	**IS EXPECTATION**																
1074					RENEWAL	-	-	-	200	200	200	200	200	200	200	400	400
1075																	
1076	**IS EXPECTATION Total**					**-**	**-**	**-**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**400**	**400**
1077																	
1078	**IM CONFIRMED**																
1079		**PAC**															
1080			04TX-11722														
1081				1195168	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
1082				77400411	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
1083		**PAC Total**				**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
1084																	
1085	**IM CONFIRMED Total**					**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
1	**FPT One-Year**															
2	**Avista**															
3		DE-MS79-85BP92186														
4			453495	LEGACY	32	32	32	32	32	32	32	32	32	32	32	32
5	**Avista Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**
6																
7	**Douglas**															
8		DE-MS79-80BP90066														
9			(blank)	LEGACY	2	2	2	2	2	2	2	2	2	2	2	2
10	**Douglas Total**				**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
11																
12	**PAC**															
13		DE-MS79-94BP94280														
14			422032	LEGACY	200	200	200	200	200	200	200	200	200	200	200	200
15		DE-MS79-94BP94333														
16			1801200	LEGACY	35	35	35	35	35	35	35	35	35	35	35	35
17			1801201	LEGACY	40	40	40	40	40	40	40	40	40	40	40	40
18			1801202	LEGACY	84	84	84	84	84	84	84	84	84	84	84	84
19			1801203	LEGACY	241	241	241	241	241	241	241	241	241	241	241	241
20			1801397	LEGACY	55	55	55	55	55	55	55	55	55	55	55	55
21			1801398	LEGACY	145	145	145	145	145	145	145	145	145	145	145	145
22	**PAC Total**				**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**
23																
24	**PRC**															
25		DE-MS79-95BP94151														
26			422176	LEGACY	50	50	50	50	50	50	50	50	50	50	50	50
27	**PRC Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
28																
29	**Puget**															
30		DE-MS79-85BP92185														
31			422177	LEGACY	32	32	32	32	32	32	32	32	32	32	32	32
32	**Puget Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**
33																
34	**FPT One-Year Total**				**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**
35																
36	**FPT Three-Year**															
37	**PAC**															
38		14-03-14612														
39			1801204/5	LEGACY	66	76	87	87	79	73	69	68	63	65	67	66
40	**PAC Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**
41																
42	**FPT Three-Year Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**
43																

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
					-	-	-	-	-	-	-	-	-	-	-	-	-
44	**IR**																
45		**Puget**															
46			14-03-45241														
47				1801608	LEGACY	266	266	266	266	266	266	266	266	266	266	266	266
48		**Puget Total**				**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
49																	
50	**IR Total**					**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
51																	
52	**PTP CONFIRMED**																
53		**Alcoa**															
54			01TX-10630														
55				77208678	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
56				77208409	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
57				77208424	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
58				77208444	RENEWAL	9	9	9	9	9	9	9	9	9	9	9	9
59				77208977	RENEWAL	47	47	47	47	47	47	47	47	47	47	47	47
60				77208984	RENEWAL	15	15	15	15	15	15	15	15	15	15	15	15
61				77208846	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
62				77208855	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
63				77208882	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
64				77208899	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
65				77208633	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
66				77208648	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
67				77208654	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
68				77208559	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
69				77208909	RENEWAL	31	31	31	31	31	31	31	31	31	31	31	31
70				77208934	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
71				77208962	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
72				77208965	RENEWAL	23	23	23	23	23	23	23	23	23	23	23	23
73				77208698	RENEWAL	22	22	22	22	22	22	22	22	22	22	22	22
74				77208709	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
75				77208661	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
76				77208675	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
77		**Alcoa Total**				**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
78																	
79		**Arlington**															
80			07TX-12526														
81				72296939	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
82		**Arlington Total**				**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
83																
84	**Avista**															
85		96MS-96008														
86			1468405	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
87			1468727	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
88			1801278	ORIGINAL	50	50	50	50	50	50	50	50	50	50	-	-
89			1801279	ORIGINAL	147	147	147	147	147	147	147	147	147	147	-	-
90			1801284	ORIGINAL	196	196	196	196	196	196	196	196	196	196	-	-
91			71358397	RECALL	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	-	-
92			73613021	ORIGINAL	125	125	125	125	125	125	125	125	125	125	125	125
93			73613033	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
94			77632744	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
95	**Avista Total**				**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**718**	**375**	**375**
96																
97	**Benton PUD**															
98		97TX-10041														
99			1800329	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
100			1800338	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
101			1800343	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
102			1800354	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
103			1801465	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
104			71821795	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
105			1800377	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
106			1800379	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
107			1801385	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
108			1800333	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
109			1800364	ORIGINAL	28	28	28	28	28	28	28	28	28	28	28	28
110			71821291	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
111			1800366	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
112			1800373	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
113			1800375	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
114	**Benton PUD Total**				**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**
115																
116	**BPA Power**															
117		02TX-11144														
118			476542	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
119			71706908	REDIRECT	24	24	24	24	24	24	24	24	24	24	24	24
120		96MS-95363														
121			1469289	ORIGINAL	300	300	300	116	116	116	116	116	116	116	116	116
122			1469291	ORIGINAL	88	88	88	88	88	88	88	88	88	88	88	88
123			1470201	ORIGINAL	109	109	109	109	109	109	109	109	109	109	109	109
124			1800939	ORIGINAL	1	1	1	1	1	1	1	1	1	-	-	-
125			1800940	ORIGINAL	2	2	2	2	2	2	2	2	2	-	-	-
126			1800941	ORIGINAL	2	2	2	2	2	2	2	2	2	-	-	-
127			1800942	ORIGINAL	2	2	2	2	2	2	2	2	2	-	-	-
128			1800943	ORIGINAL	3	3	3	3	3	3	3	3	3	-	-	-

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
129			1800944	ORIGINAL	4	4	4	4	4	4	4	4	4	-	-	-
130			1800945	ORIGINAL	5	5	5	5	5	5	5	5	5	-	-	-
131			1800946	ORIGINAL	5	5	5	5	5	5	5	5	5	-	-	-
132			1800947	ORIGINAL	6	6	6	6	6	6	6	6	6	-	-	-
133			1800948	ORIGINAL	8	8	8	8	8	8	8	8	8	-	-	-
134			1800949	ORIGINAL	12	12	12	12	12	12	12	12	12	-	-	-
135			321890	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90
136			496595	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
137			1800097	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
138			1800100	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
139			1800103	ORIGINAL	11	11	11	11	11	11	11	11	11	11	11	11
140			1800106	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
141			1800109	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
142			1800112	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
143			1800115	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
144			1800118	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
145			1800121	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
146			1800124	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
147			1800127	ORIGINAL	48	48	48	48	48	48	48	48	48	48	48	48
148			1800130	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
149			1800133	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
150			1800137	ORIGINAL	287	287	287	287	287	287	287	287	287	287	287	287
151			72844177	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
152			78395391	REDIRECT	-	-	-	184	184	184	184	184	184	184	184	184
153			77078633	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
154			77078601	RENEWAL	17	17	17	17	17	17	17	17	17	17	17	17
155			75100144	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
156		96MS-96060														
157			Multiple	ORIGINAL	667	667	667	667	667	667	667	667	667	667	667	667
158	**BPA Power Total**				**2,046**	**2,046**	**2,046**	**2,046**	**2,046**	**2,046**	**2,046**	**2,046**	**2,046**	**1,996**	**1,996**	**1,996**
159																
160	**Chelan**															
161		01TX-10714														
162			72041989	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
163	**Chelan Total**				**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
164																
165	**Clark**															
166		02TX-11177														
167			73198880	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
168			73198888	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
169			73198896	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
170	**Clark Total**				**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**	**75**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
171				-	-	-	-	-	-	-	-	-	-	-	-	-
172	**Clatskanie**															
173		01TX-10649														
174			1321619	ORIGINAL	9	9	9	9	9	9	9	9	9	9	9	9
175			1321623	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
176			1321630	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
177			1321632	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
178			1321634	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
179			1800705	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
180			1800709	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
181			1800717	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
182			1800721	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
183			1800725	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
184			1800729	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
185			1800735	ORIGINAL	14	14	14	14	14	14	14	14	14	14	14	14
186			1800737	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
187			1800740	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
188			1800741	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
189	**Clatskanie Total**				**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**
190																
191	**EDF Renewable**															
192		08TX-13169														
193			78441120	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
194	**EDF Renewable Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
195																
196	**Eurus Comb**															
197		09TX-14147														
198			73185318	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
199			73473061	REDIRECT	62	62	62	62	62	62	62	62	62	62	62	62
200	**Eurus Comb Total**				**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**
201																
202	**Finley Bioenergy**															
203		07TX-12488														
204			71689868	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
205			71915090	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
206	**Finley Bioenergy Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
207																
208	**Franklin County**															
209		97TX-10043														
210			1466591	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
211			1468490	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
212			1469388	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
213			1471445	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
214			1472430	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
215			1801660	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
216			1801665	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
217			1801670	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
218			1801675	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
219			1801680	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
220			1801685	ORIGINAL	22	22	22	22	22	22	22	22	22	22	22	22
221			1801690	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
222			1801695	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
223			1801700	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
224			1801705	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
225			1801710	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
226			71630464	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
227	**Franklin County Total**				**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**
228																
229	**Grant**															
230		01TX-10679														
231			72582664	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
232			74475223	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
233			76084927	REDIRECT	150	150	150	-	-	-	-	-	-	-	-	-
234	**Grant Total**				**162**	**162**	**162**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**
235																
236	**Grays Harbor**															
237		96MS-96083														
238			1179595	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
239			1800860	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
240			1800868	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
241			1800869	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
242			1800870	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
243			1800871	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
244			1800872	ORIGINAL	20	20	20	20	20	20	20	20	20	20	20	20
245			1800873	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
246			1800874	ORIGINAL	26	26	26	26	26	26	26	26	26	26	26	26
247			1800875	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
248			1800876	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
249			1800877	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
250			1801266	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
251			1801468	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
252			71316632	REDIRECT	8	8	8	8	8	8	8	8	8	8	8	8
253			72080322	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
254			72080765	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
255	**Grays Harbor Total**				**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
256					-	-	-	-	-	-	-	-	-	-	-	-
257	**Hermiston Power**															
258		98TX-10154														
259			1801330	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
260			1801331	ORIGINAL	308	308	308	308	308	308	308	308	308	308	308	308
261	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
262																
263	**Iberdrola**															
264		00TX-10367														
265			77895741	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
266			78287943	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
267			78495126	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
268			77079897	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
269			78495051	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
270			78495102	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
271			78577161	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
272			77410610	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
273			76523582	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
274			76523590	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
275			76523592	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
276			77079910	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
277			77410538	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
278			77410542	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
279			76523573	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
280			75648199	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
281			75402452	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
282			75402568	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
283			75402686	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	25
284			75648234	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	-
285			77325065	REDIRECT	25	25	25	25	25	25	-	-	-	-	-	-
286			77325077	REDIRECT	25	25	25	25	25	25	-	-	-	-	-	-
287			77325082	REDIRECT	25	25	25	25	25	25	-	-	-	-	-	-
288			77325070	REDIRECT	25	25	25	25	25	25	-	-	-	-	-	-
289			79556737	RECALL	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
290			78511036	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
291			78511028	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
292			78511047	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
293			78511040	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
294	**Iberdrola Total**				**700**	**700**	**700**	**700**	**700**	**700**	**600**	**600**	**600**	**600**	**600**	**600**
295																
296	**Idaho Power Company**															
297		96MS-96108														
298			1801478	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
299			1801479	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
300			1801489	ORIGINAL	53	53	53	53	53	53	53	53	53	53	53	53

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
301		12TX-15618														
302			77108132	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
303			77108133	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
304		13TX-15768														
305			77443011	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
306			77443034	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
307			77443090	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
308	**Idaho Power Company Total**				**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**
309																
310	**JC-B**															
311		13TX-15809														
312			78685544	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
313	**JC-B Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
314																
315	**Kaiser Alum WA**															
316		11TX-15371														
317			77494335	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
318	**Kaiser Alum WA Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
319																
320	**Klickitat**															
321		97TX-10038														
322			77124569	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
323			77124571	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
324			77124572	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
325			77124573	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
326			77124588	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
327			77124582	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
328			77124583	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
329			77124585	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
330			77124586	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
331			77124575	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
332			77124578	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
333			77124590	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
334			77124591	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
335			77128633	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
336			77124579	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
337			77124581	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
338	**Klickitat Total**				**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**
339																
340	**LADWP**															
341		02TX-10944														
342			78459775	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
343			78459780	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
344			78459765	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
345			78459768	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
346			78459737	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
347			78459759	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
348	**LADWP Total**				**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
349																
350	**Middle Fork**															
351		05TX-11927														
352			1466103	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
353			1469988	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
354	**Middle Fork Total**				**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
355																
356	**Northern Wasco**															
357		09TX-14164														
358			74073792	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
359	**Northern Wasco Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
360																
361	**Okanogan PUD**															
362		01TX-10686														
363			75978650	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
364			75978589	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
365			75978597	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
366			75978607	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
367			75978620	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
368			75978559	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
369			75978566	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
370			75978656	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
371			75978700	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
372			75978643	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
373			75978645	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
374			75978571	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
375			75978577	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
376			75978582	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
377			75978673	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
378			75978693	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
379			75978696	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
380			75978699	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
381			75978636	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
382			75978638	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
383			75978640	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
384			75978586	RENEWAL	13	13	13	13	13	13	13	13	13	13	13	13
385			75978634	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
386			75978524	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
387	**Okanogan PUD Total**				**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**	**115**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
388																
389	**Outback Solar**															
390		11TX-15513														
391			77028206	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
392			77247649	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
393	**Outback Solar Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
394																
395	**PAC**															
396		04TX-11722														
397			72510730	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
398			72510734	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
399			72513702	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
400			72513705	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
401			72513707	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
402			72604283	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
403			72604325	REDIRECT	80	80	80	80	80	80	80	80	80	80	80	80
404			72604332	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
405			72604342	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
406			73518379	RENEWAL	144	-	-	-	-	-	-	-	-	-	-	-
407			73518383	RENEWAL	85	-	-	-	-	-	-	-	-	-	-	-
408			73604581	RENEWAL	70	70	70	-	-	-	-	-	-	-	-	-
409			74027888	RENEWAL	222	222	222	222	222	222	222	222	222	-	-	-
410			74027903	RENEWAL	18	18	18	18	18	18	18	18	18	-	-	-
411			74636110	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	-
412			77322834	RENEWAL	76	76	76	76	76	76	76	76	76	76	76	76
413			77424318	RENEWAL	120	120	120	120	120	120	120	120	120	120	120	120
414			77424414	RENEWAL	190	190	190	190	190	190	190	190	190	190	190	190
415			77810169	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
416			76145322	ORIGINAL	137	137	137	137	137	137	137	137	137	137	137	137
417			76475596	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
418			77322753	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
419			77322823	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
420			76106891	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
421			76182574	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56
422			76191343	ORIGINAL	40	40	40	40	40	40	40	40	40	40	40	40
423			75397855	REDIRECT	100	100	100	100	100	100	100	100	100	100	100	100
424			75503469	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
425			74723497	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
426			77810173	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
427			78385466	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
428			78398821	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
429			77424479	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
430			77520585	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
431			76522087	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
432			76970392	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
433			75766088	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
434			75819074	RENEWAL	28	28	28	28	28	28	28	28	28	28	28	28
435			75841669	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
436			74754673	REDIRECT	6	-	-	-	-	-	-	-	-	-	-	-
437			75503471	REDIRECT	70	70	70	70	70	70	70	70	70	70	70	70
438			78720451	RENEWAL	146	146	146	146	146	146	146	146	146	146	146	146
439			78720471	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
440			78720493	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
441			78720629	RENEWAL	85	85	85	85	85	85	85	85	85	85	85	85
442			78720424	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
443			73518379R	RENEWAL	-	144	144	144	144	144	144	144	144	144	144	144
444			78721010	RENEWAL	88	88	88	88	88	88	88	88	88	88	88	88
445			78720215	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
446			78720311	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
447			74636110R	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	8
448			79191196	REDIRECT	38	38	38	38	38	38	38	38	38	38	38	38
449			79484622	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
450			76382678	REDIRECT	21	21	21	21	21	21	21	21	21	21	21	21
451			78763280	RENEWAL	420	420	420	420	420	420	420	420	420	420	420	420
452			78763246	RENEWAL	70	70	70	70	70	70	70	70	70	70	70	70
453	**PAC Total**				**3,189**	**3,098**	**3,098**	**3,028**	**3,028**	**3,028**	**3,028**	**3,028**	**3,028**	**2,788**	**2,788**	**2,788**
454																
455	**Patu Wind Farm**															
456		08TX-13657														
457			72649180	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
458			74128031	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
459	**Patu Wind Farm Total**				**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
460																
461	**Pend Oreille**															
462		02TX-10875														
463			76277035	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
464			76277045	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
465			76277050	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
466			76277055	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
467			76277060	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
468			76277018	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
469			76277021	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
470			76277025	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
471			76277031	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
472			76277086	RENEWAL	9	9	9	9	9	9	9	9	9	9	9	9
473			76277063	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
474			76277065	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
475			76277067	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
476	**Pend Oreille Total**				**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
477																
478	**PGE**															
479		98TX-10174														
480			73970915	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
481		09TX-14507														
482			78857909	DEFERRAL	45	45	45	45	45	45	45	45	45	45	45	45
483	**PGE Total**				**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**	**70**
484																
485	**POTB**															
486		13TX-15849														
487			78391247	DEFERRAL	1	1	1	1	1	1	1	1	1	1	1	1
488	**POTB Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
489																
490	**Powerex**															
491		96MS-96084														
492			1465922	ORIGINAL	230	230	230	230	230	230	230	230	230	230	230	230
493		99TX-10251														
494			74490405	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
495			75753552	RENEWAL	193	193	193	193	193	193	193	193	193	193	193	193
496			77478534	ORIGINAL	80	80	80	80	80	80	80	80	80	80	80	80
497			77105600	RENEWAL	102	102	102	102	102	102	102	102	102	102	102	102
498			77821635	RENEWAL	125	125	125	125	125	125	125	125	125	125	125	125
499			77821638	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
500	**Powerex Total**				**817**	**817**	**817**	**817**	**817**	**817**	**817**	**817**	**817**	**817**	**817**	**817**
501																
502	**PPL EnergyPlus**															
503		08TX-13030														
504			72408392	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
505			73063071	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
506	**PPL EnergyPlus Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
507																
508	**PRC**															
509		12TX-15681														
510			76938843	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
511	**PRC Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
512																
513	**Puget**															
514		06TX-12195														
515			1466374	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
516			1466379	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
517			1466381	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
518			1466383	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
519			1466385	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
520			1466387	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
521			1466389	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
522			1471793	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
523			1471795	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
524			1471797	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
525			1471799	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
526			1471801	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
527			1471803	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
528			1472838	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
529			1473142	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
530			71365495	RENEWAL	400	400	400	400	400	400	400	400	400	400	400	400
531			71984715	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
532			72813104	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
533			72706601	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
534			72706605	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
535			72706606	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
536			72706608	ORIGINAL	43	43	43	43	43	43	43	43	43	43	43	43
537			75012886	RENEWAL	23	23	23	23	23	-	-	-	-	-	-	-
538			77286231	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
539			77286242	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
540			77855235	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
541			76213396	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
542			76213399	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
543			76213403	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
544			77286223	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
545			73395728	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
546			76041858	RENEWAL	94	94	94	94	94	94	94	94	94	94	94	94
547			76041860	RENEWAL	160	160	160	160	160	160	160	160	160	160	160	160
548			76213391	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
549			72886051	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
550			72886075	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
551			72886101	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
552			78527177	RENEWAL	263	263	263	263	263	263	263	263	263	263	263	263
553			78527185	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
554			78527191	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
555			78510701	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
556			78510722	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
557			78510643	RENEWAL	115	115	115	115	115	115	115	115	115	115	115	115
558			77286250	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
559			77913795	RENEWAL	35	35	35	35	35	35	35	35	35	35	35	35
560			77913798	RENEWAL	27	27	27	27	27	27	27	27	27	27	27	27
561			76213405	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
562			76213407	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
563			76041854	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
564			72885921	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
565			72885963	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
566			72886013	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
567			78527159	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
568			78527166	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
569			78527170	RENEWAL	150	150	150	150	150	150	150	150	150	150	150	150
570			78903869	RENEWAL	169	169	169	169	169	169	169	169	169	169	169	169
571			78262265	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
572	**Puget Total**				**3,796**	**3,796**	**3,796**	**3,796**	**3,796**	**3,773**	**3,773**	**3,773**	**3,773**	**3,773**	**3,773**	**3,773**
573																
574	**SC Edison**															
575		10TX-14641														
576			75978147	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
577			75978181	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
578			75978191	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
579			75978193	ORIGINAL	120	120	120	120	120	120	120	120	120	120	120	120
580			76252310	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
581			76252318	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
582			76252286	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
583			76252295	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
584			76252305	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
585	**SC Edison Total**				**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**
586																
587	**Seattle**															
588		96MS-96018														
589			1800082	ORIGINAL	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023
590			1800521	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
591			1800522	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
592			1800523	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
593			1800524	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
594			1800525	ORIGINAL	46	46	46	46	46	46	46	46	46	46	46	46
595			1800526	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52
596			1800527	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
597			1800528	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
598			1800529	ORIGINAL	83	83	83	83	83	83	83	83	83	83	83	83
599			1800530	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
600			1800531	ORIGINAL	158	158	158	158	158	158	158	158	158	158	158	158
601			1801314	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
602			1801315	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
603			1801316	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
604			1801356	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
605			1801399	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90
606			1801474	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
607			1801824	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
608			71852108	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
609			73833947	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
610	**Seattle Total**				**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
611																
612	**Sherman County**															
613		04TX-11833														
614			79276006	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
615			79276016	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
616			79276024	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
617			79276106	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
618			79276111	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
619			76179605	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
620			76179608	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
621			76179591	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
622			76179597	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
623			76179603	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
624	**Sherman County Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
625																
626	**SMUD**															
627		02TX-11128														
628			77703370	DEFERRAL	30	30	30	30	30	30	30	30	30	30	30	30
629			79132005	DEFERRAL	30	30	30	30	30	30	30	30	30	30	30	30
630	**SMUD Total**				**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**
631																
632	**Snohomish**															
633		96MS-96092														
634			1800028	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
635			1800080	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
636			1801078	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
637			1801079	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
638			1801080	ORIGINAL	38	38	38	38	38	38	38	38	38	38	38	38
639			1801081	ORIGINAL	39	39	39	39	39	39	39	39	39	39	39	39
640			1801082	ORIGINAL	72	72	72	72	72	72	72	72	72	72	72	72
641			1801083	ORIGINAL	81	81	81	81	81	81	81	81	81	81	81	81
642			1801084	ORIGINAL	85	85	85	85	85	85	85	85	85	85	85	85
643			1801085	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
644			1801086	ORIGINAL	156	156	156	156	156	156	156	156	156	156	156	156
645			1801087	ORIGINAL	247	247	247	247	247	247	247	247	247	247	247	247
646			1801163	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
647			1801362	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
648			1801451	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
649			1801500	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
650			1801823	ORIGINAL	131	131	131	131	131	131	131	131	131	131	131	131
651			72566153	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
652			72566175	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
653			72566200	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
654			72673396	RECALL	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
655			72673445	RECALL	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
656			73240353	ORIGINAL	51	51	51	51	51	51	51	51	51	51	51	51

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
657			72150853	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
658			72150855	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
659			73240347	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
660			72150858	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
661	**Snohomish Total**				**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**	**1,869**
662																
663	**Tacoma Power**															
664		98TX-10103														
665			1472937	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
666			1800542	ORIGINAL	19	19	19	19	19	19	19	19	19	19	19	19
667			1800543	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
668			1800544	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
669			1800545	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
670			1800546	ORIGINAL	44	44	44	44	44	44	44	44	44	44	44	44
671			1800547	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52
672			1800548	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
673			1800550	ORIGINAL	82	82	82	82	82	82	82	82	82	82	82	82
674			1800551	ORIGINAL	99	99	99	99	99	99	99	99	99	99	99	99
675			1800565	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
676			1800566	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
677			1800567	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
678			1800568	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
679			1800569	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
680			1800570	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
681			1800571	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
682			1800572	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
683			1800573	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
684			1800574	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
685			1801317	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
686			1801318	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
687			1801319	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
688			1801501	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
689			71851948	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
690			71851958	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
691			71984719	REDIRECT	48	48	48	48	48	48	48	48	48	48	48	48
692			71984725	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
693			72032784	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
694			75108469	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
695			75108338	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
696			75724017	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56
697			75108487	RECALL	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
698			75108431	RECALL	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
699			1800552	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
700			1800549	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
701	**Tacoma Power Total**				**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**
702																

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
703	**TEMUS**															
704		98TX-10172														
705			73918209	ORIGINAL	100	100	100	100	100	100	-	-	-	-	-	-
706			73918184	ORIGINAL	50	50	50	50	50	50	-	-	-	-	-	-
707			78976989	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
708	**TEMUS Total**				**250**	**250**	**250**	**250**	**250**	**250**	**100**	**100**	**100**	**100**	**100**	**100**
709																
710	**Turlock Irrigation**															
711		00TX-10344														
712			77517818	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
713			77517830	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
714	**Turlock Irrigation Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
715																
716	**Wheat Field Wind**															
717		08TX-13610														
718			72458260	ORIGINAL	97	97	97	97	97	97	97	97	97	97	97	97
719	**Wheat Field Wind Total**				**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
720																
721	**PTP CONFIRMED Total**				**20,393**	**20,302**	**20,302**	**20,082**	**20,082**	**20,059**	**19,809**	**19,809**	**19,809**	**19,519**	**19,176**	**19,176**
722																
723	**PTP CONFIRMED NO SCD**															
724	**L & M**															
725		06TX-12244														
726			72873760	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
727	**L & M Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
728																
729	**Lower Valley**															
730		08TX-13671														
731			78866292	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
732	**Lower Valley Total**				**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
733																
734	**Raft River Energy**															
735		07TX-12449														
736			1471160	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
737	**Raft River Energy Total**				**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**
738																
739	**UAMPS**															
740		11TX-15512														
741			77309382	ORIGINAL	53	53	53	53	53	53	53	53	53	53	53	53
742	**UAMPS Total**				**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**
743																
744	**PTP CONFIRMED NO SCD Total**				**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**	**68**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
PTP SDD															
Avista															
	96MS-96008														
		77632744	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
Avista Total				**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**
Franklin County															
	97TX-10043														
		1472430	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Franklin County Total				**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**
Grant															
	01TX-10679														
		76084927	SDD	(60)	(60)	(60)	-	-	-	-	-	-	-	-	-
Grant Total				**(60)**	**(60)**	**(60)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Iberdrola															
	00TX-10367														
		78287943	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
		77079897	SDD	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
		77410610	SDD	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
		77079910	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
		77410538	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
		77410542	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Iberdrola Total				**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**
Idaho Power Company															
	12TX-15618														
		77108132	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
		77108133	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Idaho Power Company Total				**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**
JC-B															
	13TX-15809														
		78685544	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
JC-B Total				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
Middle Fork															
	05TX-11927														
		1466103	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
		1469988	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Middle Fork Total				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
788				-	-	-	-	-	-	-	-	-	-	-	-	-
789	**PAC**															
790		04TX-11722														
791			73518379	SDD	(58)	-	-	-	-	-	-	-	-	-	-	-
792			73518383	SDD	(22)	-	-	-	-	-	-	-	-	-	-	-
793			77424318	SDD	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
794			77424414	SDD	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
795			77810169	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
796			77322823	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
797			76191343	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
798			74723497	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
799			77810173	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
800			77424479	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
801			76522087	SDD	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
802	**PAC Total**				**(248)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**	**(168)**
803																
804	**POTB**															
805		13TX-15849														
806			78391247	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
807	**POTB Total**				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
808																
809	**Raft River Energy**															
810		07TX-12449														
811			1471160	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
812	**Raft River Energy Total**				**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**
813																
814	**SC Edison**															
815		10TX-14641														
816			75978147	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
817			75978181	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
818			75978191	SDD	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
819			75978193	SDD	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
820			76252310	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
821			76252318	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
822			76252286	SDD	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
823			76252295	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
824			76252305	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
825	**SC Edison Total**				**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**
826																
827	**SMUD**															
828		02TX-11128														
829			77703370	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
830	**SMUD Total**				**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
831																
832	**UAMPS**															
833		11TX-15512														
834			77309382	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
835	**UAMPS Total**				**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**
836																
837	**PTP SDD Total**				**(507.0)**	**(427.7)**	**(427.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**	**(367.7)**
838																
839	**PTP CF CONFIRMED**															
840	**Iberdrola**															
841		00TX-10367														
842			78738359	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
843	**Iberdrola Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
844																
845	**LADWP**															
846		02TX-10944														
847			74228809	ORIGINAL	50	50	-	-	-	-	-	-	-	-	-	-
848	**LADWP Total**				**50**	**50**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
849																
850	**PAC**															
851		04TX-11722														
852			77119166	REDIRECT	88	88	88	88	88	88	88	88	88	88	88	88
853			75846783	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
854	**PAC Total**				**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**
855																
856	**PGE**															
857		09TX-14507														
858			78858032	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
859	**PGE Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
860																
861	**Puget**															
862		06TX-12195														
863			74856145	ORIGINAL	12	12	-	-	-	-	-	-	-	-	-	-
864			76945532	ORIGINAL	8	8	8	8	8	8	8	8	-	-	-	-
865			77565922	ORIGINAL	50	50	50	-	-	-	-	-	-	-	-	-
866			77565931	ORIGINAL	40	40	40	-	-	-	-	-	-	-	-	-
867	**Puget Total**				**110**	**110**	**98**	**8**	**8**	**8**	**8**	**8**	**-**	**-**	**-**	**-**
868																
869	**Shell Energy**															
870		00TX-10286														
871			74928222	DEFERRAL	125	125	125	125	125	125	125	-	-	-	-	-
872	**Shell Energy Total**				**125**	**125**	**125**	**125**	**125**	**125**	**125**	**-**	**-**	**-**	**-**	**-**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
873					-	-	-	-	-	-	-	-	-	-	-	-	-
874		**TEMUS**															
875			98TX-10172														
876				74623822	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
877				74623837	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
878				79132196	RECALL	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
879		**TEMUS Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
880																	
881	**PTP CF CONFIRMED Total**					**623**	**623**	**561**	**471**	**471**	**471**	**471**	**346**	**338**	**338**	**338**	**338**
882																	
883	**PTP EXPECTATION**																
884					RENEWAL	4,595	4,686	4,736	4,956	4,956	4,979	5,229	5,229	5,229	5,469	5,812	5,812
885					RECALL	(125)	(125)	(125)	(125)	(125)	(125)	(125)	(125)	(125)	(125)	(125)	(125)
886					ORIGINAL	50	50	50	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
887																	
888	**PTP EXPECTATION Total**					**4,520**	**4,611**	**4,661**	**5,893**	**5,893**	**5,916**	**6,166**	**6,166**	**6,166**	**6,406**	**6,749**	**6,749**
889																	
890	**PTP SDD EXPECTATION**																
891						(37)	(116)	(119)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)	(179)
892																	
893	**PTP SDD EXPECTATION Total**					**(37)**	**(116)**	**(119)**	**(179)**	**(179)**	**(179)**	**(179)**	**(179)**	**(179)**	**(179)**	**(179)**	**(179)**
894																	
895	**PTP CF EXPECTATION**																
896					DEFERRAL (RECALL)	(150)	(50)	-	-	-	-	-	-	-	-	-	-
897					RENEWAL	-	-	12	12	12	12	12	137	145	145	145	145
898					ORIGINAL	600	600	600	600	600	600	600	600	600	600	600	600
899																	
900	**PTP CF EXPECTATION Total**					**450**	**550**	**612**	**612**	**612**	**612**	**612**	**737**	**745**	**745**	**745**	**745**
901																	
902	**IS CONFIRMED**																
903		**BPA Power**															
904			96MS-95363														
905				321873	ORIGINAL	700	700	700	700	700	700	700	700	700	700	700	700
906				321874	ORIGINAL	300	300	300	300	300	300	300	300	300	300	300	300
907				483765	ORIGINAL	50	50	50	50	50	50	50	50	50	-	-	-
908			96MS-96060														
909				71383980	ORIGINAL	60	15	15	15	15	15	15	-	-	-	-	-
910		**BPA Power Total**				**1,110**	**1,065**	**1,065**	**1,065**	**1,065**	**1,065**	**1,065**	**1,050**	**1,050**	**1,000**	**1,000**	**1,000**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
911				-	-	-	-	-	-	-	-	-	-	-	-	-
912	**Exelon Generation**															
913		02TX-11265														
914			78225336	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
915			78225361	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
916			78225363	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
917			78221134	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
918	**Exelon Generation Total**				**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**
919																
920	**Hermiston Power**															
921		98TX-10154														
922			1800038	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
923			1801359	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
924			449487	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
925			449491	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
926			449493	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
927	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
928																
929	**Iberdrola**															
930		00TX-10367														
931			71678981	ORIGINAL	280	280	280	280	280	280	280	280	280	280	280	280
932			1466882	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
933			72154100	ORIGINAL	-	35	35	35	35	35	35	35	35	35	35	35
934			72288164	ORIGINAL	12	-	-	-	-	-	-	-	-	-	-	-
935			72552123	ORIGINAL	15	-	-	-	-	-	-	-	-	-	-	-
936			72511486	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
937			72511519	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
938			76659161	RENEWAL	95	95	95	95	95	95	95	95	95	95	95	95
939			72511528	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
940			76303736	RENEWAL	47	47	47	47	47	47	47	47	47	47	47	47
941			77719214	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
942			78154124	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
943			75596535	RENEWAL	100	100	100	100	100	100	100	100	100	-	-	-
944			76303714	RENEWAL	180	180	180	180	180	180	180	180	180	180	180	180
945			76303727	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
946			76303731	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
947	**Iberdrola Total**				**1,002**	**1,010**	**1,010**	**1,010**	**1,010**	**1,010**	**1,010**	**1,010**	**1,010**	**910**	**910**	**910**
948																
949	**Morgan Stanley**															
950		97TX-10031														
951			1470598	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
952			1467616	ORIGINAL	-	10	10	-	-	-	-	-	-	-	-	-
953			1470752	ORIGINAL	-	-	-	-	-	-	-	-	-	50	50	50
954			1470754	ORIGINAL	-	-	-	-	-	-	-	15	15	15	15	15
955			72398097	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
956			72921329	ORIGINAL	-	27	27	-	-	-	-	-	-	-	-	-
957			1470382	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
958			1470384	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
959			1470386	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
960			1470388	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
961			73014940	ORIGINAL	73	73	73	-	-	-	-	-	-	-	-	-
962			75533108	RENEWAL	46	46	46	46	46	46	46	46	46	46	46	46
963			73016708	ORIGINAL	27	-	-	-	-	-	-	-	-	-	-	-
964			78676775	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
965			78454535	ORIGINAL	-	-	-	15	15	15	15	15	15	15	15	15
966	**Morgan Stanley Total**				**400**	**410**	**410**	**315**	**315**	**315**	**315**	**330**	**330**	**380**	**380**	**380**
967																
968	**PAC**															
969		DE-MS79-94BP94285														
970			427472	ORIGINAL	93	93	93	93	93	93	93	93	93	93	93	93
971			866020	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
972	**PAC Total**				**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**
973																
974	**Powerex**															
975		99TX-10251														
976			72742268	RENEWAL	50	50	50	50	50	50	50	50	50	-	-	-
977			78710047	RENEWAL	200	200	200	200	200	200	200	200	200	200	200	200
978			79100585	RENEWAL	51	51	51	51	51	51	51	51	51	51	51	51
979			79100588	RENEWAL	150	150	150	150	150	150	150	150	150	150	150	150
980			79461718	RENEWAL	49	49	49	49	49	49	49	49	49	49	49	49
981			75322538	RENEWAL	24	24	24	24	24	24	24	24	-	-	-	-
982			75322539	RENEWAL	15	15	15	15	15	15	15	15	-	-	-	-
983			75322540	RENEWAL	11	11	11	11	11	11	11	11	-	-	-	-
984			77502254	RENEWAL	357	357	357	357	357	357	357	357	357	357	357	357
985			77543772	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
986			77543773	RENEWAL	286	286	286	286	286	286	286	286	286	286	286	286
987			77543781	RENEWAL	650	650	650	650	650	650	650	650	650	650	650	650
988	**Powerex Total**				**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,835**	**1,785**	**1,785**	**1,785**
989																
990	**Shell Energy**															
991		00TX-10286														
992			72429308	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
993			72513298	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
994			72513308	RENEWAL	20	20	20	20	20	20	20	20	20	20	20	20
995			72513313	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
996	**Shell Energy Total**				**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**

Table 13.2
2016 Long-Term Transmission Demand
(Megawatts)

	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
997					-	-	-	-	-	-	-	-	-	-	-	-	-
998		TEMUS															
999			98TX-10172														
1000				77302316	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
1001				78163252	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
1002		**TEMUS Total**				**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**
1003																	
1004	**IS CONFIRMED Total**					**5,509**	**5,482**	**5,482**	**5,387**	**5,387**	**5,387**	**5,387**	**5,387**	**5,337**	**5,187**	**5,187**	**5,187**
1005																	
1006	**IS EXPECTATION**																
1007					RENEWAL	574	574	574	684	684	684	684	684	734	884	884	884
1008																	
1009	**IS EXPECTATION Total**					**574**	**574**	**574**	**684**	**684**	**684**	**684**	**684**	**734**	**884**	**884**	**884**
1010																	
1011	**IM CONFIRMED**																
1012		**PAC**															
1013			04TX-11722														
1014				1195168	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
1015				77400411	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
1016		**PAC Total**				**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
1017																	
1018	**IM CONFIRMED Total**					**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
1	**FPT One-Year**															
2	**Avista**															
3		DE-MS79-85BP92186														
4			453495	LEGACY	32	32	32	32	32	32	32	32	32	32	32	32
5	**Avista Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**
6																
7	**Douglas**															
8		DE-MS79-80BP90066														
9			(blank)	LEGACY	2	2	2	2	2	2	2	2	2	2	2	2
10	**Douglas Total**				**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
11																
12	**PAC**															
13		DE-MS79-94BP94280														
14			422032	LEGACY	200	200	200	200	200	200	200	200	200	200	200	200
15		DE-MS79-94BP94333														
16			1801200	LEGACY	35	35	35	35	35	35	35	35	35	35	35	35
17			1801201	LEGACY	40	40	40	40	40	40	40	40	40	40	40	40
18			1801202	LEGACY	84	84	84	84	84	84	84	84	84	84	84	84
19			1801203	LEGACY	241	241	241	241	241	241	241	241	241	241	241	241
20			1801397	LEGACY	55	55	55	55	55	55	55	55	55	55	55	55
21			1801398	LEGACY	145	145	145	145	145	145	145	145	145	145	145	145
22	**PAC Total**				**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**
23																
24	**PRC**															
25		DE-MS79-95BP94151														
26			422176	LEGACY	50	50	50	50	50	50	50	50	50	50	50	50
27	**PRC Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
28																
29	**Puget**															
30		DE-MS79-85BP92185														
31			422177	LEGACY	32	32	32	32	32	32	32	32	32	-	-	-
32	**Puget Total**				**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**32**	**-**	**-**	**-**
33																
34	**FPT One-Year Total**				**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**917**	**884**	**884**	**884**
35																
36	**FPT Three-Year**															
37	**PAC**															
38		14-03-14612														
39			1801204/5	LEGACY	66	76	87	87	79	73	69	68	63	65	67	66
40	**PAC Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**
41																
42	**FPT Three-Year Total**				**66**	**76**	**87**	**87**	**79**	**73**	**69**	**68**	**63**	**65**	**67**	**66**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
43																	
44	**IR**																
45		**Puget**															
46			14-03-45241														
47				1801608	LEGACY	266	266	266	266	266	266	266	266	266	266	266	266
48		**Puget Total**				**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
49																	
50	**IR Total**					**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**	**266**
51																	
52	**PTP CONFIRMED**																
53		**Alcoa**															
54			01TX-10630														
55				77208678	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
56				77208409	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
57				77208424	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
58				77208444	RENEWAL	9	9	9	9	9	9	9	9	9	9	9	9
59				77208977	RENEWAL	47	47	47	47	47	47	47	47	47	47	47	47
60				77208984	RENEWAL	15	15	15	15	15	15	15	15	15	15	15	15
61				77208846	RENEWAL	26	26	26	26	26	26	26	26	26	26	26	26
62				77208855	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
63				77208882	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
64				77208899	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
65				77208633	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
66				77208648	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
67				77208654	RENEWAL	11	11	11	11	11	11	11	11	11	11	11	11
68				77208559	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
69				77208909	RENEWAL	31	31	31	31	31	31	31	31	31	31	31	31
70				77208934	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
71				77208962	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
72				77208965	RENEWAL	23	23	23	23	23	23	23	23	23	23	23	23
73				77208698	RENEWAL	22	22	22	22	22	22	22	22	22	22	22	22
74				77208709	RENEWAL	7	7	7	7	7	7	7	7	7	7	7	7
75				77208661	RENEWAL	3	3	3	3	3	3	3	3	3	3	3	3
76				77208675	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
77		**Alcoa Total**				**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**	**403**
78																	
79		**Arlington**															
80			07TX-12526														
81				72296939	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
82		**Arlington Total**				**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
83				-	-	-	-	-	-	-	-	-	-	-	-	-
84	**Avista**															
85		96MS-96008														
86			1468405	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
87			1468727	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
88			73613021	ORIGINAL	125	125	125	125	125	125	125	125	125	125	125	125
89			73613033	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
90			77632744	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
91	**Avista Total**				**375**	**375**	**375**	**375**	**375**	**375**	**375**	**375**	**375**	**375**	**375**	**375**
92																
93	**Benton PUD**															
94		97TX-10041														
95			1800329	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
96			1800338	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
97			1800343	ORIGINAL	16	16	16	16	16	16	16	16	16	16	16	16
98			1800354	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
99			1801465	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
100			71821795	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
101			1800377	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
102			1800379	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
103			1801385	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
104			1800333	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
105			1800364	ORIGINAL	28	28	28	28	28	28	28	28	28	28	28	28
106			71821291	REDIRECT	6	6	6	6	6	6	6	6	6	6	6	6
107			1800366	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
108			1800373	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
109			1800375	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
110	**Benton PUD Total**				**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**	**423**
111																
112	**BPA Power**															
113		02TX-11144														
114			476542	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
115			71706908	REDIRECT	24	24	24	24	24	24	24	24	24	24	24	24
116		96MS-95363														
117			1469289	ORIGINAL	116	116	116	116	116	116	116	116	116	300	300	300
118			1469291	ORIGINAL	88	88	88	88	88	88	88	88	88	88	88	88
119			1470201	ORIGINAL	109	109	109	109	109	109	109	109	109	109	109	109
120			321890	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90
121			496595	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
122			1800097	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
123			1800100	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
124			1800103	ORIGINAL	11	11	11	11	11	11	11	11	11	11	11	11
125			1800106	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
126			1800109	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
127			1800112	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
128			1800115	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
129			1800118	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
130			1800121	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
131			1800124	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
132			1800127	ORIGINAL	48	48	48	48	48	48	48	48	48	48	48	48
133			1800130	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
134			1800133	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
135			1800137	ORIGINAL	287	287	287	287	287	287	287	287	287	287	287	287
136			72844177	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
137			78395391	REDIRECT	184	184	184	184	184	184	184	184	184	-	-	-
138			77078633	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
139			77078601	RENEWAL	17	17	17	17	17	17	17	17	17	17	17	17
140			75100144	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
141		96MS-96060														
142			Multiple	ORIGINAL	667	667	667	667	667	667	667	667	667	667	667	667
143	**BPA Power Total**				**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**	**1,996**
144																
145	**Chelan**															
146		01TX-10714														
147			72041989	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
148	**Chelan Total**				**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**	**8**
149																
150	**Clatskanie**															
151		01TX-10649														
152			1321619	ORIGINAL	9	9	9	9	9	9	9	9	9	9	9	9
153			1321623	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
154			1321630	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
155			1321632	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
156			1321634	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
157			1800705	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
158			1800709	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
159			1800717	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
160			1800721	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
161			1800725	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
162			1800729	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
163			1800735	ORIGINAL	14	14	14	14	14	14	14	14	14	14	14	14
164			1800737	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
165			1800740	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
166			1800741	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
167	**Clatskanie Total**				**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**	**147**
168																
169	**EDF Renewable**															
170		08TX-13169														
171			78441120	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
172	**EDF Renewable Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
173				-	-	-	-	-	-	-	-	-	-	-	-	-
174	**Eurus Comb**															
175		09TX-14147														
176			73185318	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
177			73473061	REDIRECT	62	62	62	62	62	62	62	62	62	62	62	62
178	**Eurus Comb Total**				**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**	**62**
179																
180	**Finley Bioenergy**															
181		07TX-12488														
182			71689868	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
183			71915090	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
184	**Finley Bioenergy Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
185																
186	**Franklin County**															
187		97TX-10043														
188			1466591	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
189			1468490	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
190			1469388	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
191			1471445	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
192			1472430	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
193			1801660	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8
194			1801665	ORIGINAL	27	27	27	27	27	27	27	27	27	27	27	27
195			1801670	ORIGINAL	17	17	17	17	17	17	17	17	17	17	17	17
196			1801675	ORIGINAL	42	42	42	42	42	42	42	42	42	42	42	42
197			1801680	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
198			1801685	ORIGINAL	22	22	22	22	22	22	22	22	22	22	22	22
199			1801690	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
200			1801695	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
201			1801700	ORIGINAL	7	7	7	7	7	7	7	7	7	7	7	7
202			1801705	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
203			1801710	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
204			71630464	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
205	**Franklin County Total**				**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**	**183**
206																
207	**Grant**															
208		01TX-10679														
209			74475223	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
210	**Grant Total**				**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**
211																
212	**Grays Harbor**															
213		96MS-96083														
214			1179595	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
215			1800860	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
216			1800868	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
217			1800869	ORIGINAL	8	8	8	8	8	8	8	8	8	8	8	8

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
218			1800870	ORIGINAL	10	10	10	10	10	10	10	10	10	10	10	10
219			1800871	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
220			1800872	ORIGINAL	20	20	20	20	20	20	20	20	20	20	20	20
221			1800873	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
222			1800874	ORIGINAL	26	26	26	26	26	26	26	26	26	26	26	26
223			1800875	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
224			1800876	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
225			1800877	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
226			1801266	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
227			1801468	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
228			71316632	REDIRECT	8	8	8	8	8	8	8	8	8	8	8	8
229			72080322	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
230			72080765	REDIRECT	2	2	2	2	2	2	2	2	2	2	2	2
231	**Grays Harbor Total**				**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**
232																
233	**Hermiston Power**															
234		98TX-10154														
235			1801330	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
236			1801331	ORIGINAL	308	308	308	308	308	308	308	308	308	308	308	308
237	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
238																
239	**Iberdrola**															
240		00TX-10367														
241			77895741	ORIGINAL	21	21	21	21	21	21	21	21	21	21	21	21
242			78287943	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
243			78495126	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
244			77079897	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	-
245			78495051	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
246			78495102	DEFERRAL	20	20	20	20	20	20	20	20	20	20	20	20
247			78577161	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
248			77410610	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
249			77079910	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	-
250			77410538	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
251			77410542	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
252			75648199	REDIRECT	25	25	-	-	-	-	-	-	-	-	-	-
253			75402452	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
254			75402568	RENEWAL	-	-	25	25	25	25	25	25	25	25	25	25
255			75402686	RENEWAL	25	25	25	25	25	25	25	25	25	25	25	25
256			79556737	RECALL	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
257			78511036	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
258			78511028	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
259			78511047	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
260			78511040	DEFERRAL	25	25	25	25	25	25	25	25	25	25	25	25
261	**Iberdrola Total**				**600**	**600**	**600**	**600**	**600**	**600**	**600**	**600**	**600**	**600**	**600**	**450**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
262																
263	**Idaho Power Company**															
264		12TX-15618														
265			77108132	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
266			77108133	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
267		13TX-15768														
268			77443011	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
269			77443034	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
270			77443090	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
271	**Idaho Power Company Total**				**119**	**119**	**119**	**119**	**119**	**119**	**119**	**119**	**119**	**119**	**119**	**119**
272																
273	**JC-B**															
274		13TX-15809														
275			78685544	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
276	**JC-B Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
277																
278	**Kaiser Alum WA**															
279		11TX-15371														
280			77494335	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
281	**Kaiser Alum WA Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
282																
283	**Klickitat**															
284		97TX-10038														
285			77124569	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
286			77124571	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
287			77124572	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
288			77124573	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
289			77124588	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
290			77124582	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
291			77124583	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
292			77124585	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
293			77124586	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
294			77124575	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
295			77124578	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
296			77124590	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
297			77124591	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
298			77128633	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
299			77124579	RENEWAL	6	6	6	6	6	6	6	6	6	6	6	6
300			77124581	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
301	**Klickitat Total**				**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
302																
303	**LADWP**															
304		02TX-10944														
305			78459775	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
306			78459780	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
307			78459765	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
308			78459768	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
309			78459737	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
310			78459759	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
311	**LADWP Total**				**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
312																
313	**Middle Fork**															
314		05TX-11927														
315			1466103	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
316			1469988	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
317	**Middle Fork Total**				**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
318																
319	**Northern Wasco**															
320		09TX-14164														
321			74073792	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
322	**Northern Wasco Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
323																
324	**Outback Solar**															
325		11TX-15513														
326			77028206	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
327			77247649	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
328	**Outback Solar Total**				**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
329																
330	**PAC**															
331		04TX-11722														
332			72510730	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
333			72510734	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
334			72513702	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
335			72513705	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
336			72513707	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
337			72604283	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
338			72604325	REDIRECT	80	80	80	80	80	80	80	80	80	80	80	80
339			72604332	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
340			72604342	REDIRECT	-	-	-	-	-	-	-	-	-	-	-	-
341			77322834	RENEWAL	76	76	76	76	76	76	76	76	76	76	76	76
342			77424318	RENEWAL	120	120	120	120	120	120	120	120	120	120	120	120
343			77424414	RENEWAL	190	190	190	190	190	190	190	190	190	190	190	190
344			77810169	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
345			76145322	ORIGINAL	137	137	137	-	-	-	-	-	-	-	-	-
346			76475596	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
347			77322753	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
348			77322823	RENEWAL	5	5	5	5	5	5	5	5	5	5	5	5
349			76106891	RENEWAL	4	4	4	4	4	4	4	4	4	-	-	-
350			76182574	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56
351			76191343	ORIGINAL	40	-	-	-	-	-	-	-	-	-	-	-
352			75397855	REDIRECT	100	100	100	100	100	100	100	100	100	100	100	100
353			75503469	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
354			74723497	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
355			77810173	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
356			78385466	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
357			78398821	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
358			77424479	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
359			77520585	RENEWAL	2	2	2	2	2	2	2	2	2	2	2	2
360			76522087	RENEWAL	75	75	75	75	75	75	-	-	-	-	-	-
361			76970392	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
362			75766088	RENEWAL	1	1	1	1	1	1	1	1	1	-	-	-
363			75819074	RENEWAL	28	28	28	28	28	28	28	28	28	-	-	-
364			75841669	ORIGINAL	1	1	1	1	1	1	1	1	1	-	-	-
365			75503471	REDIRECT	70	70	70	70	70	70	70	70	70	70	70	70
366			78720451	RENEWAL	146	146	146	146	146	146	146	146	146	146	146	146
367			78720471	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
368			78720493	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
369			78720629	RENEWAL	85	85	85	85	85	85	85	85	85	85	85	85
370			78720424	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
371			73518379R	RENEWAL	144	144	144	144	144	144	144	144	144	144	144	144
372			78721010	RENEWAL	88	88	88	88	88	88	88	88	88	88	88	88
373			78720215	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
374			78720311	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
375			74636110R	RENEWAL	8	8	8	8	8	8	8	8	8	8	8	8
376			79191196	REDIRECT	38	38	38	38	38	-	-	-	-	-	-	-
377			79484622	ORIGINAL	5	5	5	5	5	5	5	5	5	5	5	5
378			76382678	REDIRECT	21	21	-	-	-	-	-	-	-	-	-	-
379			78763280	RENEWAL	420	420	420	420	420	420	420	420	420	420	420	420
380			78763246	RENEWAL	70	70	70	70	70	70	70	70	70	70	70	70
381	**PAC Total**				**2,788**	**2,748**	**2,727**	**2,590**	**2,590**	**2,552**	**2,477**	**2,477**	**2,477**	**2,443**	**2,443**	**2,443**
382																
383	**Patu Wind Farm**															
384		08TX-13657														
385			72649180	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
386			74128031	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
387	**Patu Wind Farm Total**				**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
388				-	-	-	-	-	-	-	-	-	-	-	-	-
389	**Pend Oreille**															
390		02TX-10875														
391			76277035	RENEWAL	3	3	3	-	-	-	-	-	-	-	-	-
392			76277045	RENEWAL	3	3	3	-	-	-	-	-	-	-	-	-
393			76277050	RENEWAL	2	2	2	-	-	-	-	-	-	-	-	-
394			76277055	RENEWAL	1	1	1	-	-	-	-	-	-	-	-	-
395			76277060	RENEWAL	1	1	1	-	-	-	-	-	-	-	-	-
396			76277018	RENEWAL	6	6	6	-	-	-	-	-	-	-	-	-
397			76277021	RENEWAL	5	5	5	-	-	-	-	-	-	-	-	-
398			76277025	RENEWAL	4	4	4	-	-	-	-	-	-	-	-	-
399			76277031	RENEWAL	3	3	3	-	-	-	-	-	-	-	-	-
400			76277086	RENEWAL	9	9	9	-	-	-	-	-	-	-	-	-
401			76277063	RENEWAL	1	1	1	-	-	-	-	-	-	-	-	-
402			76277065	RENEWAL	1	1	1	-	-	-	-	-	-	-	-	-
403			76277067	RENEWAL	1	1	1	-	-	-	-	-	-	-	-	-
404	**Pend Oreille Total**				**40**	**40**	**40**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
405																
406	**PGE**															
407		98TX-10174														
408			73970915	ORIGINAL	25	25	-	-	-	-	-	-	-	-	-	-
409		09TX-14507														
410			78857909	DEFERRAL	45	45	45	45	45	45	45	45	45	45	45	45
411	**PGE Total**				**70**	**70**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**	**45**
412																
413	**POTB**															
414		13TX-15849														
415			78391247	DEFERRAL	1	1	1	1	1	1	1	1	1	1	1	1
416	**POTB Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
417																
418	**Powerex**															
419		96MS-96084														
420			1465922	ORIGINAL	230	230	230	230	230	230	230	230	230	230	230	230
421		99TX-10251														
422			74490405	RENEWAL	12	12	12	12	12	12	12	12	12	12	12	12
423			77478534	ORIGINAL	80	80	80	80	80	80	80	80	80	80	80	80
424			77105600	RENEWAL	102	102	102	102	102	102	102	102	102	102	102	102
425			77821635	RENEWAL	125	125	125	125	125	125	125	125	125	125	125	125
426			77821638	RENEWAL	75	75	75	75	75	75	75	75	75	75	75	75
427	**Powerex Total**				**624**	**624**	**624**	**624**	**624**	**624**	**624**	**624**	**624**	**624**	**624**	**624**

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
428				-	-	-	-	-	-	-	-	-	-	-	-	-
429	**PPL EnergyPlus**															
430		08TX-13030														
431			72408392	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
432			73063071	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
433	**PPL EnergyPlus Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
434																
435	**PRC**															
436		12TX-15681														
437			76938843	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
438	**PRC Total**				**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**
439																
440	**Puget**															
441		06TX-12195														
442			1466374	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
443			1466379	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
444			1466381	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
445			1466383	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
446			1466385	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
447			1466387	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
448			1466389	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
449			1471793	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
450			1471795	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
451			1471797	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
452			1471799	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
453			1471801	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
454			1471803	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
455			1472838	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
456			1473142	REDIRECT	250	250	250	250	250	250	250	250	250	250	250	250
457			71365495	RENEWAL	400	400	400	400	400	400	400	400	400	400	400	400
458			71984715	REDIRECT	5	5	5	5	5	5	5	5	5	5	5	5
459			72813104	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
460			72706601	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
461			72706605	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
462			72706606	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
463			72706608	ORIGINAL	43	43	43	43	43	43	43	43	43	43	43	43
464			77286231	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
465			77286242	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
466			77855235	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
467			76213396	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
468			76213399	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
469			76213403	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
470			77286223	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
471			73395728	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
472			76041860	RENEWAL	160	160	160	160	160	160	160	160	160	160	160	160
473			76213391	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
474			72886051	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
475			72886075	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
476			72886101	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
477			78527177	RENEWAL	263	263	263	263	263	263	263	263	263	263	263	263
478			78527185	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
479			78527191	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
480			78510701	RENEWAL	300	300	300	300	300	300	300	300	300	300	300	300
481			78510722	RENEWAL	4	4	4	4	4	4	4	4	4	4	4	4
482			78510643	RENEWAL	115	115	115	115	115	115	115	115	115	115	115	115
483			77286250	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
484			77913795	RENEWAL	35	35	35	35	35	35	35	35	35	35	35	35
485			77913798	RENEWAL	27	27	27	27	27	27	27	27	27	27	27	27
486			76213405	REDIRECT	25	25	25	25	25	25	25	25	25	25	25	25
487			76213407	REDIRECT	50	50	50	50	50	50	50	50	50	50	50	50
488			72885921	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
489			72885963	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
490			72886013	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
491			78527159	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
492			78527166	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
493			78527170	RENEWAL	150	150	150	150	150	150	150	150	150	150	150	150
494			78903869	RENEWAL	169	169	169	169	169	169	169	169	169	169	169	169
495			78262265	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
496	**Puget Total**				**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**	**3,579**
497																
498	**SC Edison**															
499		10TX-14641														
500			75978147	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
501			75978181	ORIGINAL	35	35	35	35	35	35	35	35	35	35	35	35
502			75978191	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
503			75978193	ORIGINAL	120	120	120	120	120	120	120	120	120	120	120	120
504			76252310	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
505			76252318	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
506			76252286	ORIGINAL	29	29	29	29	29	29	29	29	29	29	29	29
507			76252295	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
508			76252305	ORIGINAL	115	115	115	115	115	115	115	115	115	115	115	115
509	**SC Edison Total**				**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**	**724**
510																
511	**Seattle**															
512		96MS-96018														
513			1800082	ORIGINAL	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023	1,023
514			1800521	ORIGINAL	18	18	18	18	18	18	18	18	18	18	18	18
515			1800522	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
516			1800523	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
517			1800524	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
518			1800525	ORIGINAL	46	46	46	46	46	46	46	46	46	46	46	46
519			1800526	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
520			1800527	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
521			1800528	ORIGINAL	65	65	65	65	65	65	65	65	65	65	65	65
522			1800529	ORIGINAL	83	83	83	83	83	83	83	83	83	83	83	83
523			1800530	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
524			1800531	ORIGINAL	158	158	158	158	158	158	158	158	158	158	158	158
525			1801314	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
526			1801315	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
527			1801316	ORIGINAL	4	4	4	4	4	4	4	4	4	4	4	4
528			1801356	ORIGINAL	36	36	36	36	36	36	36	36	36	36	36	36
529			1801399	ORIGINAL	90	90	90	90	90	90	90	90	90	90	90	90
530			1801474	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
531			1801824	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
532			71852108	ORIGINAL	62	62	62	62	62	62	62	62	62	62	62	62
533			73833947	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
534	**Seattle Total**				**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**	**1,962**
535																
536	**Sherman County**															
537		04TX-11833														
538			79276006	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
539			79276016	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
540			79276024	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
541			79276106	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
542			79276111	RECALL	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
543			76179605	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
544			76179608	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
545			76179591	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
546			76179597	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
547			76179603	DEFERRAL	10	10	10	10	10	10	10	10	10	10	10	10
548	**Sherman County Total**				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
549																
550	**SMUD**															
551		02TX-11128														
552			77703370	DEFERRAL	30	30	30	30	30	30	30	30	30	30	30	30
553			79132005	DEFERRAL	30	30	30	30	30	30	30	30	30	30	30	30
554	**SMUD Total**				**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**	**60**
555																
556	**Snohomish**															
557		96MS-96092														
558			1800028	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
559			1800080	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
560			1801078	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
561			1801079	ORIGINAL	37	37	37	37	37	37	37	37	37	37	37	37
562			1801080	ORIGINAL	38	38	38	38	38	38	38	38	38	38	38	38
563			1801081	ORIGINAL	39	39	39	39	39	39	39	39	39	39	39	39
564			1801082	ORIGINAL	72	72	72	72	72	72	72	72	72	72	72	72

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
565			1801083	ORIGINAL	81	81	81	81	81	81	81	81	81	81	81	81
566			1801084	ORIGINAL	85	85	85	85	85	85	85	85	85	85	85	85
567			1801085	ORIGINAL	102	102	102	102	102	102	102	102	102	102	102	102
568			1801086	ORIGINAL	156	156	156	156	156	156	156	156	156	156	156	156
569			1801087	ORIGINAL	247	247	247	247	247	247	247	247	247	247	247	247
570			1801163	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
571			1801362	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
572			1801451	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
573			1801500	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
574			1801823	ORIGINAL	131	131	131	131	131	131	131	131	131	131	131	131
575			72566153	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
576			72566175	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
577			72566200	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
578			72673396	RECALL	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
579			72673445	RECALL	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
580			73240353	ORIGINAL	51	51	51	51	51	51	51	51	51	51	51	51
581			72150853	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
582			72150855	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
583			73240347	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
584			72150858	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
585			72150867	ORIGINAL	-	-	-	25	25	25	25	25	25	25	25	25
586			72436399	ORIGINAL	-	-	-	25	25	25	25	25	25	25	25	25
587	**Snohomish Total**				**1,869**	**1,869**	**1,869**	**1,919**	**1,919**	**1,919**	**1,919**	**1,919**	**1,919**	**1,919**	**1,919**	**1,919**
588																
589	**Tacoma Power**															
590		98TX-10103														
591			1472937	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
592			1800542	ORIGINAL	19	19	19	19	19	19	19	19	19	19	19	19
593			1800543	ORIGINAL	23	23	23	23	23	23	23	23	23	23	23	23
594			1800544	ORIGINAL	24	24	24	24	24	24	24	24	24	24	24	24
595			1800545	ORIGINAL	25	25	25	25	25	25	25	25	25	25	25	25
596			1800546	ORIGINAL	44	44	44	44	44	44	44	44	44	44	44	44
597			1800547	ORIGINAL	52	52	52	52	52	52	52	52	52	52	52	52
598			1800548	ORIGINAL	54	54	54	54	54	54	54	54	54	54	54	54
599			1800550	ORIGINAL	82	82	82	82	82	82	82	82	82	82	82	82
600			1800551	ORIGINAL	99	99	99	99	99	99	99	99	99	99	99	99
601			1800565	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
602			1800566	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
603			1800567	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
604			1800568	ORIGINAL	1	1	1	1	1	1	1	1	1	1	1	1
605			1800569	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
606			1800570	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
607			1800571	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
608			1800572	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
609			1800573	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
610			1800574	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
		-		-	-	-	-	-	-	-	-	-	-	-	-	-
611			1801317	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
612			1801318	ORIGINAL	2	2	2	2	2	2	2	2	2	2	2	2
613			1801319	ORIGINAL	3	3	3	3	3	3	3	3	3	3	3	3
614			1801501	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
615			71851948	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
616			71851958	ORIGINAL	-	-	-	-	-	-	-	-	-	-	-	-
617			71984719	REDIRECT	48	48	48	48	48	48	48	48	48	48	48	48
618			71984725	REDIRECT	10	10	10	10	10	10	10	10	10	10	10	10
619			72032784	REDIRECT	3	3	3	3	3	3	3	3	3	3	3	3
620			75108469	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
621			75108338	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
622			75724017	RENEWAL	56	56	56	56	56	56	56	56	56	56	56	56
623			75108487	RECALL	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)	(155)
624			75108431	RECALL	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
625			1800552	ORIGINAL	155	155	155	155	155	155	155	155	155	155	155	155
626			1800549	ORIGINAL	64	64	64	64	64	64	64	64	64	64	64	64
627	**Tacoma Power Total**				**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**	**801**
628																
629	**Turlock Irrigation**															
630		00TX-10344														
631			77517818	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
632			77517830	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
633	**Turlock Irrigation Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
634																
635	**Wheat Field Wind**															
636		08TX-13610														
637			72458260	ORIGINAL	97	97	97	97	97	97	97	97	97	97	97	97
638	**Wheat Field Wind Total**				**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
639																
640	**PTP CONFIRMED Total**				**18,438**	**18,398**	**18,352**	**18,225**	**18,225**	**18,187**	**18,112**	**18,112**	**18,112**	**18,078**	**18,078**	**17,928**
641																
642	**PTP CONFIRMED NO SCD**															
643	**L & M**															
644		06TX-12244														
645			72873760	RENEWAL	1	1	1	1	1	1	1	1	1	1	1	1
646	**L & M Total**				**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
647																
648	**Raft River Energy**															
649		07TX-12449														
650			1471160	ORIGINAL	12	12	12	12	12	12	12	12	12	12	12	12
651	**Raft River Energy Total**				**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**	**12**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
	UAMPS															
		11TX-15512														
			77309382	ORIGINAL	53	53	53	53	53	53	53	53	53	53	53	-
	UAMPS Total				**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**53**	**-**
PTP CONFIRMED NO SCD Total					**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**13**
PTP SDD																
	Avista															
		96MS-96008														
			77632744	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
	Avista Total				**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**
	Franklin County															
		97TX-10043														
			1472430	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	Franklin County Total				**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**	**(1)**
	Iberdrola															
		00TX-10367														
			78287943	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
			77079897	SDD	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	-
			77410610	SDD	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
			77079910	SDD	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	-
			77410538	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
			77410542	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
	Iberdrola Total				**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(44)**	**(36)**
	Idaho Power Company															
		12TX-15618														
			77108132	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
			77108133	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
	Idaho Power Company Total				**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**	**(2.7)**
	JC-B															
		13TX-15809														
			78685544	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	JC-B Total				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
	Middle Fork															
		05TX-11927														
			1466103	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
			1469988	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Middle Fork Total				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
				-	-	-	-	-	-	-	-	-	-	-	-	-
697																
698	**PAC**															
699		04TX-11722														
700			77424318	SDD	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
701			77424414	SDD	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
702			77810169	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
703			77322823	SDD	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
704			76191343	SDD	(16)	-	-	-	-	-	-	-	-	-	-	-
705			74723497	SDD	(8)	(8)	-	-	-	-	-	-	-	-	-	-
706			77810173	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
707			77424479	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
708			76522087	SDD	(20)	(20)	(20)	(20)	(20)	(20)	-	-	-	-	-	-
709	**PAC Total**				**(168)**	**(152)**	**(144)**	**(144)**	**(144)**	**(144)**	**(125)**	**(125)**	**(125)**	**(125)**	**(125)**	**(125)**
710																
711	**POTB**															
712		13TX-15849														
713			78391247	SDD	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
714	**POTB Total**				**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**
715																
716	**Raft River Energy**															
717		07TX-12449														
718			1471160	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
719	**Raft River Energy Total**				**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**	**(2)**
720																
721	**SC Edison**															
722		10TX-14641														
723			75978147	SDD	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
724			75978181	SDD	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
725			75978191	SDD	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
726			75978193	SDD	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
727			76252310	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
728			76252318	SDD	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
729			76252286	SDD	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
730			76252295	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
731			76252305	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
732	**SC Edison Total**				**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**	**(124)**
733																
734	**SMUD**															
735		02TX-11128														
736			77703370	SDD	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
737			79132005	SDD	-	-	-	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
738	**SMUD Total**				**(2)**	**(2)**	**(2)**	**(4)**	**(4)**	**(4)**	**(4)**	**(4)**	**(4)**	**(4)**	**(4)**	**(4)**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status	Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
					-	-	-	-	-	-	-	-	-	-	-	-	-
739																	
740		**UAMPS**															
741			11TX-15512														
742				77309382	SDD	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	-
743		**UAMPS Total**				**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**(16)**	**-**
744																	
745	**PTP SDD Total**					**(367.7)**	**(351.7)**	**(343.6)**	**(345.7)**	**(345.7)**	**(345.7)**	**(326.1)**	**(326.1)**	**(326.1)**	**(326.1)**	**(326.1)**	**(302.6)**
746																	
747	**PTP CF CONFIRMED**																
748		**Iberdrola**															
749			00TX-10367														
750																	
751				78738359	DEFERRAL	50	50	50	50	50	50	50	50	50	50	50	50
752		**Iberdrola Total**				**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**
753																	
754		**PAC**															
755			04TX-11722														
756				77119166	REDIRECT	88	88	88	88	88	88	88	88	88	-	-	-
757				75846783	RENEWAL	-	-	-	-	-	-	-	-	-	-	-	-
758		**PAC Total**				**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**88**	**-**	**-**	**-**
759																	
760		**PGE**															
761			09TX-14507														
762				78858032	DEFERRAL	100	100	100	100	100	100	100	100	100	100	100	100
763		**PGE Total**				**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
764																	
765	**PTP CF CONFIRMED Total**					**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**150**	**150**	**150**
766																	
767	**PTP EXPECTATION**																
768					RENEWAL	6,549	6,589	6,614	6,791	6,791	6,829	6,904	6,904	6,904	6,970	6,970	7,120
769					DEFERRAL(RECALL)	(125)	(80)	(80)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
770					ORIGINAL	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,162	1,162
771																	
772	**PTP EXPECTATION Total**					**7,486**	**7,571**	**7,596**	**7,803**	**7,803**	**7,841**	**7,916**	**7,916**	**7,916**	**7,982**	**8,082**	**8,232**
773																	
774	**PTP EXPECTATION NO SCD**																
775					RENEWAL	-	-	-	-	-	-	-	-	-	-	-	53
776																	
777	**PTP EXPECTATION NO SCD Total**					**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**53**
778																	
779	**PTP SDD EXPECTATION**																
780					SDD	(179)	(195)	(195)	(195)	(195)	(195)	(214)	(214)	(214)	(214)	(214)	(238)
781																	
782	**PTP SDD EXPECTATION Total**					**(179)**	**(195)**	**(195)**	**(195)**	**(195)**	**(195)**	**(214)**	**(214)**	**(214)**	**(214)**	**(214)**	**(238)**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
783																
784	**PTP CF EXPECTATION**															
785				RENEWAL	245	245	245	245	245	245	245	245	245	333	333	333
786				ORIGINAL	600	600	600	600	600	600	600	600	600	600	600	600
787																
788	**PTP CF EXPECTATION Total**				**845**	**845**	**845**	**845**	**845**	**845**	**845**	**845**	**845**	**933**	**933**	**933**
789																
790	**IS CONFIRMED**															
791	**BPA Power**															
792		96MS-95363														
793			321873	ORIGINAL	700	700	700	700	700	700	-	-	-	-	-	-
794			321874	ORIGINAL	300	300	300	300	300	300	-	-	-	-	-	-
795			1472326	ORIGINAL	-	-	-	-	-	-	700	700	700	700	700	700
796			73834974	ORIGINAL	-	-	-	-	-	-	15	15	15	15	15	15
797	**BPA Power Total**				**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**715**	**715**	**715**	**715**	**715**	**715**
798																
799	**Exelon Generation**															
800		02TX-11265														
801			78225336	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
802			78225361	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
803			78225363	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
804			78221134	ORIGINAL	30	30	30	30	30	30	30	30	30	30	30	30
805	**Exelon Generation Total**				**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**
806																
807	**Hermiston Power**															
808		98TX-10154														
809			1800038	ORIGINAL	228	228	228	228	228	228	228	228	228	228	228	228
810			1801359	ORIGINAL	75	75	75	75	75	75	75	75	75	75	75	75
811			449487	ORIGINAL	33	33	33	33	33	33	33	33	33	33	33	33
812			449491	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
813			449493	ORIGINAL	100	100	100	100	100	100	100	100	100	100	100	100
814	**Hermiston Power Total**				**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**	**536**
815																
816	**Iberdrola**															
817		00TX-10367														
818			71678981	ORIGINAL	280	280	280	280	280	280	280	280	280	280	280	280
819			1466882	ORIGINAL	15	15	15	-	-	-	-	-	-	-	-	-
820			72154100	ORIGINAL	35	35	35	-	-	-	-	-	-	-	-	-
821			73167623	ORIGINAL	-	-	-	-	-	-	50	50	50	50	50	50
822			73167628	ORIGINAL	-	-	-	-	-	-	50	50	50	50	50	50
823			73167629	ORIGINAL	-	-	-	-	-	-	50	50	50	50	50	50
824			73598438	ORIGINAL	-	-	-	-	-	-	50	50	50	50	50	50
825			76659161	RENEWAL	95	95	95	95	95	95	95	-	-	-	-	-
826			76303736	RENEWAL	47	47	47	-	-	-	-	-	-	-	-	-
827			77719214	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
828			78154124	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
829			76303714	RENEWAL	180	180	180	-	-	-	-	-	-	-	-	-
830			76303727	RENEWAL	75	75	75	-	-	-	-	-	-	-	-	-
831			76303731	RENEWAL	8	8	8	-	-	-	-	-	-	-	-	-
832	**Iberdrola Total**				**807**	**807**	**807**	**447**	**447**	**447**	**647**	**552**	**552**	**552**	**552**	**552**
833																
834	**Morgan Stanley**															
835		97TX-10031														
836			1470598	ORIGINAL	15	15	15	-	-	-	-	-	-	-	-	-
837			1470752	ORIGINAL	50	50	50	50	50	50	50	50	50	50	50	50
838			1470754	ORIGINAL	15	15	15	15	15	15	15	15	15	15	15	15
839			72398097	ORIGINAL	-	-	-	-	-	-	85	85	85	85	85	85
840			1470382	ORIGINAL	50	50	50	-	-	-	-	-	-	-	-	-
841			1470384	ORIGINAL	50	50	50	-	-	-	-	-	-	-	-	-
842			1470386	ORIGINAL	50	50	50	-	-	-	-	-	-	-	-	-
843			1470388	ORIGINAL	50	50	50	-	-	-	-	-	-	-	-	-
844			75533108	RENEWAL	46	46	46	46	46	46	46	46	-	-	-	-
845			78676775	RENEWAL	39	39	39	39	39	39	39	39	39	39	39	39
846			78454535	ORIGINAL	15	15	15	15	15	15	-	-	-	-	-	-
847	**Morgan Stanley Total**				**380**	**380**	**380**	**165**	**165**	**165**	**235**	**235**	**189**	**189**	**189**	**189**
848																
849	**PAC**															
850		DE-MS79-94BP94285														
851			427472	ORIGINAL	93	93	93	93	93	93	93	93	93	93	93	93
852			866020	ORIGINAL	71	71	71	71	71	71	71	71	71	71	71	71
853	**PAC Total**				**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**	**164**
854																
855	**Powerex**															
856		99TX-10251														
857			78710047	RENEWAL	200	200	200	200	200	200	200	200	200	200	200	200
858			79100585	RENEWAL	51	51	51	51	51	51	51	51	51	51	51	51
859			79100588	RENEWAL	150	150	150	150	150	150	150	150	150	150	150	150
860			79461718	RENEWAL	49	49	49	49	49	49	49	49	49	49	49	49
861			77502254	RENEWAL	357	357	357	357	357	357	357	357	357	357	357	357
862			77543772	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
863			77543773	RENEWAL	286	286	286	286	286	286	286	286	286	286	286	286
864			77543781	RENEWAL	650	650	650	650	650	650	650	650	650	650	650	650
865	**Powerex Total**				**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**	**1,785**

Table 13.3
2017 Long-Term Transmission Demand
(Megawatts)

Line	Rate/Status Company	Contract	ARef	Type	(A) Oct	(b) Nov	(c) Dec	(d) Jan	(e) Feb	(f) Mar	(g) Apr	(h) May	(i) Jun	(j) Jul	(k) Aug	(l) Sep
866				-	-	-	-	-	-	-	-	-	-	-	-	-
867	**Shell Energy**															
868		00TX-10286														
869			72429308	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
870			72513298	RENEWAL	50	50	50	50	50	50	50	50	50	50	50	50
871			72513308	RENEWAL	20	20	20	20	20	20	20	20	20	20	20	20
872			72513313	RENEWAL	30	30	30	30	30	30	30	30	30	30	30	30
873	**Shell Energy Total**				**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**
874																
875	**TEMUS**															
876		98TX-10172														
877			77302316	RENEWAL	100	100	100	100	100	100	100	100	100	100	100	100
878			78163252	RENEWAL	42	42	42	42	42	42	42	42	42	42	42	42
879	**TEMUS Total**				**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**	**142**
880																
881	**IS CONFIRMED Total**				**5,084**	**5,084**	**5,084**	**4,509**	**4,509**	**4,509**	**4,494**	**4,399**	**4,353**	**4,353**	**4,353**	**4,353**
882																
883	**IS EXPECTATION**															
884				RENEWAL	987	987	987	1,562	1,562	1,562	1,562	1,657	1,703	1,703	1,703	1,703
885				ORIGINAL	-	-	120	120	120	120	120	120	120	120	120	120
886																
887	**IS EXPECTATION Total**				**987**	**987**	**1,107**	**1,682**	**1,682**	**1,682**	**1,682**	**1,777**	**1,823**	**1,823**	**1,823**	**1,823**
888																
889	**IM CONFIRMED**															
890	**PAC**															
891		04TX-11722														
892			1195168	ORIGINAL	6	6	6	6	6	6	6	6	6	6	6	6
893			77400411	RENEWAL	10	10	10	10	10	10	10	10	10	10	10	10
894	**PAC Total**				**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**
895																
896	**IM CONFIRMED Total**				**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**	**16**

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
Albion	NT Billing Factor	2016	0.505	0.634	0.753	0.705	0.692	0.589	0.489	0.352	0.344	0.420	0.416	0.344	6.243
Albion	NT Billing Factor	2017	0.508	0.637	0.757	0.708	0.696	0.592	0.492	0.355	0.348	0.424	0.420	0.347	6.284
Alder	NT Billing Factor	2016	0.845	1.027	0.886	1.101	1.036	0.943	0.753	0.459	0.407	0.477	0.462	0.417	8.813
Alder	NT Billing Factor	2017	0.854	1.035	0.892	1.109	1.043	0.951	0.759	0.465	0.413	0.484	0.470	0.422	8.897
Ashland	NT Billing Factor	2016	24.069	29.189	31.941	30.566	30.627	27.900	25.219	21.114	24.214	31.621	32.081	26.867	335.408
Ashland	NT Billing Factor	2017	24.191	29.336	32.102	30.721	30.781	28.041	25.347	21.222	24.337	31.781	32.243	27.004	337.106
Asotin PUD	NT Billing Factor	2016	0.357	0.311	0.152	0.176	0.142	0.095	0.146	0.525	0.888	0.898	0.521	0.383	4.594
Asotin PUD	NT Billing Factor	2017	0.360	0.313	0.153	0.177	0.143	0.096	0.147	0.529	0.895	0.904	0.526	0.387	4.630
Avista	NT Billing Factor	2016	58.653	76.386	82.855	69.410	68.268	64.373	57.500	62.244	80.341	81.561	66.136	49.198	816.925
Avista	NT Billing Factor	2017	58.577	76.296	82.771	69.330	68.194	64.293	57.426	62.143	80.238	81.451	66.046	49.091	815.856
Bandon	NT Billing Factor	2016	9.316	10.355	11.962	12.697	11.962	11.579	10.397	7.176	6.517	6.435	6.723	6.382	111.501
Bandon	NT Billing Factor	2017	9.362	10.407	12.022	12.761	12.022	11.638	10.449	7.211	6.550	6.466	6.757	6.414	112.059
Benton REA	NT Billing Factor	2016	75.580	77.701	79.382	0.000	77.706	69.233	75.611	80.575	94.739	106.997	106.545	97.290	941.359
Benton REA	NT Billing Factor	2017	76.450	78.578	80.245	0.000	78.564	70.019	76.478	81.483	95.806	108.206	107.743	98.394	951.966
Big Bend	NT Billing Factor	2016	46.569	41.186	45.723	45.137	37.289	31.808	59.752	81.612	121.607	125.962	117.450	95.038	849.133
Big Bend	NT Billing Factor	2017	46.850	41.577	46.110	45.522	37.638	32.133	60.084	81.930	122.019	126.377	117.872	95.429	853.541
Blaine	NT Billing Factor	2016	10.828	13.038	13.585	13.236	12.682	11.736	10.303	9.369	8.698	9.757	8.597	9.317	131.146
Blaine	NT Billing Factor	2017	10.956	13.169	13.715	13.363	12.810	11.864	10.421	9.492	8.819	9.893	8.715	9.443	132.660
Bonners Ferry	NT Billing Factor	2016	9.400	11.887	12.609	11.491	10.522	10.366	8.832	7.610	8.425	9.039	9.356	8.616	118.153
Bonners Ferry	NT Billing Factor	2017	9.408	11.895	12.616	11.498	10.528	10.373	8.838	7.616	8.432	9.046	9.364	8.622	118.236
Bonners Ferry	Short Distance Discount	2016	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-14.400
Bonners Ferry	Short Distance Discount	2017	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-1.200	-14.400
Burley	NT Billing Factor	2016	14.406	17.704	19.102	20.516	18.713	16.566	15.118	13.139	15.894	17.954	17.412	14.317	200.841
Burley	NT Billing Factor	2017	14.420	17.718	19.117	20.529	18.727	16.581	15.133	13.152	15.907	17.968	17.427	14.331	201.010
Canby	NT Billing Factor	2016	24.371	29.282	31.066	31.429	30.657	27.239	24.778	22.264	24.187	28.364	29.081	25.998	328.716
Canby	NT Billing Factor	2017	24.553	29.460	31.237	31.600	30.831	27.409	24.944	22.429	24.353	28.543	29.257	26.170	330.786
Cascade Locks	NT Billing Factor	2016	2.658	3.160	3.511	3.619	3.530	3.035	2.551	2.043	2.163	2.255	2.330	2.089	32.944
Cascade Locks	NT Billing Factor	2017	2.658	3.160	3.511	3.619	3.530	3.035	2.551	2.043	2.163	2.255	2.330	2.089	32.944

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
42	Central Lincoln	NT Billing Factor	2016	161.769	181.189	193.879	199.130	193.585	165.330	167.679	131.349	125.016	124.903	122.585	123.341	1,889.755
43	Central Lincoln	NT Billing Factor	2017	162.170	181.639	194.359	199.623	194.067	165.739	168.093	131.673	125.326	125.212	122.888	123.646	1,894.435
44																
45	Centralia	NT Billing Factor	2016	35.376	41.950	48.427	40.087	39.819	33.032	30.463	19.744	21.055	28.869	32.104	29.270	400.196
46	Centralia	NT Billing Factor	2017	35.892	42.493	49.021	40.613	40.362	33.543	30.981	20.195	21.573	29.456	32.685	29.811	406.625
47	Centralia	Short Distance Discount	2016	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-39.696
48	Centralia	Short Distance Discount	2017	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-3.308	-39.696
49																
50	Cheney	NT Billing Factor	2016	19.843	24.056	24.936	24.729	23.919	23.811	20.961	17.430	17.634	20.789	21.238	20.267	259.613
51	Cheney	NT Billing Factor	2017	20.115	24.387	25.278	25.071	24.250	24.139	21.252	17.670	17.875	21.071	21.526	20.539	263.173
52																
53	Chewelah	NT Billing Factor	2016	3.184	3.870	4.072	4.017	3.546	3.118	2.925	2.573	2.751	3.137	2.926	2.617	38.736
54	Chewelah	NT Billing Factor	2017	3.184	3.870	4.072	4.017	3.546	3.118	2.925	2.573	2.751	3.137	2.926	2.617	38.736
55																
56	Clallam	NT Billing Factor	2016	93.242	124.610	160.802	133.878	135.737	122.561	109.869	48.595	55.450	65.229	64.584	57.314	1,171.871
57	Clallam	NT Billing Factor	2017	94.062	125.585	161.900	134.765	136.650	123.466	110.802	49.242	56.261	66.275	65.592	58.058	1,182.658
58																
59	Clark	NT Billing Factor	2016	591.608	777.667	884.080	870.093	789.143	734.282	624.140	635.799	588.782	647.083	712.509	627.287	8,482.473
60	Clark	NT Billing Factor	2017	594.570	781.559	888.505	874.447	793.093	737.957	627.263	638.981	591.731	650.323	716.076	630.426	8,524.931
61	Clark	Short Distance Discount	2016	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-960.000
62	Clark	Short Distance Discount	2017	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-80.000	-960.000
63																
64	Columbia Basin	NT Billing Factor	2016	11.201	13.249	15.665	13.948	12.947	12.882	15.315	16.844	19.244	18.969	16.896	15.699	182.859
65	Columbia Basin	NT Billing Factor	2017	11.228	13.279	15.703	13.982	12.979	12.913	15.352	16.884	19.291	19.013	16.937	15.736	183.297
66																
67	Columbia Power	NT Billing Factor	2016	2.450	3.263	4.100	3.530	2.962	2.896	2.388	3.033	3.821	4.722	4.106	3.498	40.769
68	Columbia Power	NT Billing Factor	2017	2.459	3.275	4.115	3.543	2.973	2.906	2.396	3.045	3.837	4.742	4.122	3.511	40.924
69																
70	Columbia REA	NT Billing Factor	2016	33.431	27.901	28.548	25.018	22.994	24.098	41.518	50.100	84.711	93.907	90.494	70.525	593.245
71	Columbia REA	NT Billing Factor	2017	33.822	28.287	28.938	25.367	23.318	24.431	41.998	50.586	85.415	94.658	91.258	71.208	599.286
72																
73	Columbia River	NT Billing Factor	2016	61.208	80.322	87.795	81.742	78.444	75.278	64.266	59.121	57.773	61.393	66.960	64.430	838.732
74	Columbia River	NT Billing Factor	2017	61.560	80.911	88.454	82.321	78.998	75.832	64.646	59.511	58.159	61.749	67.352	64.866	844.359
75																
76	Consolidated	NT Billing Factor	2016	0.041	0.150	0.178	0.215	0.142	0.140	0.227	0.129	0.674	0.235	0.223	0.492	2.846
77	Consolidated	NT Billing Factor	2017	0.041	0.150	0.178	0.215	0.142	0.140	0.227	0.129	0.674	0.235	0.223	0.492	2.846
78																
79	Coulee Dam	NT Billing Factor	2016	2.302	3.342	4.417	3.743	3.178	3.039	1.445	1.351	1.900	2.013	2.183	2.148	31.061
80	Coulee Dam	NT Billing Factor	2017	2.350	3.396	4.471	3.794	3.223	3.089	1.474	1.392	1.957	2.069	2.237	2.200	31.652
81																

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
82	Cowlitz	NT Billing Factor	2016	508.709	565.031	654.783	634.860	586.378	547.761	535.325	542.316	511.887	509.200	499.606	529.696	6,625.552
83	Cowlitz	NT Billing Factor	2017	520.906	580.005	669.241	643.848	599.190	558.229	546.485	556.577	517.955	513.541	502.677	533.164	6,741.818
84																
85	Declo	NT Billing Factor	2016	0.462	0.565	0.612	0.606	0.563	0.508	0.458	0.393	0.359	0.421	0.414	0.419	5.780
86	Declo	NT Billing Factor	2017	0.462	0.565	0.612	0.606	0.563	0.508	0.458	0.393	0.359	0.421	0.414	0.419	5.780
87																
88	DOE-RL	NT Billing Factor	2016	16.754	-0.001	0.000	38.065	29.013	32.114	21.091	23.759	24.714	28.529	26.697	24.357	265.092
89	DOE-RL	NT Billing Factor	2017	19.458	0.000	0.000	31.291	26.365	29.696	20.802	23.436	24.373	28.137	26.335	24.019	253.912
90																
91	Drain	NT Billing Factor	2016	2.615	2.508	3.047	3.184	2.971	2.626	2.423	1.775	1.747	1.846	1.873	1.763	28.378
92	Drain	NT Billing Factor	2017	2.621	2.514	3.055	3.191	2.979	2.632	2.429	1.779	1.751	1.850	1.878	1.767	28.446
93																
94	East End	NT Billing Factor	2016	2.683	3.710	3.779	3.685	3.505	3.034	2.958	4.071	5.820	5.841	4.775	4.072	47.933
95	East End	NT Billing Factor	2017	2.732	3.773	3.837	3.743	3.562	3.089	3.008	4.126	5.885	5.905	4.836	4.132	48.628
96																
97	Eatonville	NT Billing Factor	2016	3.569	5.623	6.633	5.524	5.600	5.721	4.358	3.337	2.736	2.736	3.014	2.921	51.772
98	Eatonville	NT Billing Factor	2017	3.578	5.637	6.650	5.537	5.614	5.735	4.368	3.345	2.743	2.743	3.021	2.928	51.899
99																
100	Ellensburg	NT Billing Factor	2016	31.199	34.829	33.655	37.068	35.826	31.039	27.380	24.628	28.755	30.429	31.872	29.204	375.884
101	Ellensburg	NT Billing Factor	2017	31.500	35.152	33.954	37.370	36.146	31.348	27.675	24.926	29.069	30.721	32.187	29.507	379.555
102																
103	Elmhurst	NT Billing Factor	2016	53.654	56.600	69.039	61.079	64.499	53.754	43.777	29.310	25.784	32.507	30.244	28.490	548.737
104	Elmhurst	NT Billing Factor	2017	54.017	56.925	69.397	61.402	64.846	54.074	44.065	29.575	26.059	32.844	30.565	28.771	552.540
105																
106	Emerald	NT Billing Factor	2016	72.396	104.144	117.876	105.529	104.475	103.310	79.415	83.721	79.769	86.674	85.084	83.192	1,105.585
107	Emerald	NT Billing Factor	2017	72.840	104.749	118.551	106.139	105.085	103.902	79.899	84.209	80.245	87.191	85.600	83.689	1,112.099
108	Emerald	Short Distance Discount	2016	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-13.440
109	Emerald	Short Distance Discount	2017	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-1.120	-13.440
110																
111	Energy Northwest	NT Billing Factor	2016	1.573	1.019	1.865	1.528	1.456	0.989	1.342	0.789	0.992	0.832	1.599	0.906	14.890
112	Energy Northwest	NT Billing Factor	2017	1.387	0.895	1.591	1.808	1.678	1.126	1.534	0.897	1.133	0.931	1.755	1.034	15.769
113																
114	EWEB	NT Billing Factor	2016	303.959	372.072	403.494	368.835	386.174	326.501	295.596	252.833	282.854	314.831	317.935	288.799	3,913.883
115	EWEB	NT Billing Factor	2017	306.654	375.155	406.773	372.043	389.437	329.373	298.197	255.057	285.155	317.452	320.658	291.300	3,947.254
116	EWEB	Short Distance Discount	2016	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-315.369
117	EWEB	Short Distance Discount	2017	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-26.281	-315.369
118																
119	Fairchild	NT Billing Factor	2016	5.635	6.363	6.271	6.438	5.913	5.835	6.377	5.628	7.108	8.206	8.033	6.135	77.942
120	Fairchild	NT Billing Factor	2017	5.678	6.411	6.318	6.486	5.957	5.878	6.424	5.670	7.162	8.267	8.093	6.181	78.525
121																

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
122	Farmers	NT Billing Factor	2016	0.606	0.783	0.955	0.928	0.795	0.706	0.511	0.496	0.533	0.568	0.547	0.486	7.914
123	Farmers	NT Billing Factor	2017	0.609	0.786	0.958	0.930	0.798	0.708	0.513	0.498	0.535	0.570	0.549	0.488	7.942
124																
125	Ferry	NT Billing Factor	2016	12.730	17.071	17.498	17.620	16.564	16.208	13.494	11.556	11.127	11.765	12.191	10.041	167.865
126	Ferry	NT Billing Factor	2017	12.832	17.205	17.639	17.768	16.700	16.338	13.603	11.648	11.211	11.851	12.282	10.118	169.195
127																
128	Flathead	NT Billing Factor	2016	216.191	262.347	291.666	251.962	260.068	236.071	195.769	167.980	174.128	207.415	194.775	182.489	2,640.861
129	Flathead	NT Billing Factor	2017	218.878	265.593	295.292	255.084	261.374	239.011	198.235	170.141	176.518	209.970	197.218	184.814	2,672.128
130	Flathead	Short Distance Discount	2016	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-5.642
131	Flathead	Short Distance Discount	2017	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-0.470	-5.642
132																
133	Forest Grove	NT Billing Factor	2016	38.821	41.861	44.334	46.896	46.703	40.786	36.666	29.951	31.619	35.265	37.010	33.547	463.459
134	Forest Grove	NT Billing Factor	2017	39.197	42.268	44.774	47.354	47.159	41.184	37.022	30.241	31.926	35.606	37.371	33.870	467.972
135																
136																
137	Glacier	NT Billing Factor	2016	24.105	28.202	30.613	28.748	29.243	27.120	21.346	20.497	21.383	24.209	21.879	20.964	298.309
138	Glacier	NT Billing Factor	2017	24.286	28.414	30.842	28.964	29.463	27.323	21.506	20.651	21.543	24.390	22.043	21.121	300.546
139																
140	Grant	NT Billing Factor	2016	5.914	10.139	10.602	11.709	9.200	6.411	6.563	4.570	4.753	5.970	5.974	4.621	86.426
141	Grant	NT Billing Factor	2017	5.967	10.196	10.655	11.768	9.256	6.458	6.616	4.617	4.804	6.026	6.030	4.674	87.067
142																
143	Harney	NT Billing Factor	2016	10.007	10.837	12.653	10.630	10.238	10.122	17.537	33.556	40.570	54.404	52.048	41.803	304.405
144	Harney	NT Billing Factor	2017	10.010	10.842	12.658	10.636	10.243	10.126	17.542	33.573	40.592	54.438	52.078	41.821	304.559
145																
146	Hermiston	NT Billing Factor	2016	14.043	16.911	19.201	17.193	15.001	14.561	11.977	12.417	18.567	22.271	21.181	19.041	202.364
147	Hermiston	NT Billing Factor	2017	14.043	16.911	19.201	17.193	15.536	14.561	11.977	12.417	18.567	22.271	21.181	19.041	202.899
148																
149	Heyburn	NT Billing Factor	2016	7.699	8.808	9.265	9.478	8.955	8.474	7.756	7.256	7.657	7.841	8.011	7.458	98.658
150	Heyburn	NT Billing Factor	2017	7.978	9.090	9.542	9.752	9.229	8.747	8.025	7.549	7.951	8.130	8.309	7.759	102.061
151																
152	Hood River	NT Billing Factor	2016	16.910	19.756	18.617	20.984	18.278	19.912	13.970	13.524	11.597	12.631	16.262	18.057	200.498
153	Hood River	NT Billing Factor	2017	17.072	19.946	18.797	21.186	18.453	20.102	14.104	13.652	11.705	12.749	16.415	18.228	202.409
154																
155	Idaho County	NT Billing Factor	2016	8.171	9.623	11.828	9.381	9.268	9.223	7.034	6.740	5.536	6.436	6.619	6.370	96.229
156	Idaho County	NT Billing Factor	2017	8.232	9.697	11.917	9.452	9.339	9.293	7.088	6.792	5.581	6.489	6.670	6.421	96.971
157																
158	Idaho Falls Power	NT Billing Factor	2016	90.962	115.208	128.816	130.986	124.951	104.082	93.615	82.354	95.632	101.767	100.587	85.939	1,254.899
159	Idaho Falls Power	NT Billing Factor	2017	91.391	115.656	129.249	131.428	125.382	104.492	94.041	82.776	96.077	102.219	101.040	86.379	1,260.130
160																
161	Inland	NT Billing Factor	2016	129.266	157.119	185.070	164.529	143.466	147.058	120.567	117.871	119.826	138.452	133.860	126.869	1,683.953
162	Inland	NT Billing Factor	2017	130.573	158.743	186.979	166.247	144.928	148.552	121.759	119.033	120.987	139.829	135.185	128.116	1,700.931

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
163																
164	Jefferson	NT Billing Factor	2016	42.507	62.938	75.890	61.585	56.790	61.175	48.490	43.160	38.013	36.886	35.725	35.248	598.407
165	Jefferson	NT Billing Factor	2017	42.943	63.407	76.486	62.056	57.244	61.685	48.900	43.640	38.550	37.460	36.280	35.671	604.322
166																
167	Kittitas	NT Billing Factor	2016	14.090	16.280	18.974	17.527	15.508	14.335	11.432	11.448	11.099	13.891	13.472	11.968	170.024
168	Kittitas	NT Billing Factor	2017	14.258	16.451	19.131	17.654	15.626	14.426	11.505	11.547	11.203	13.985	13.590	12.119	171.495
169																
170	Kootenai	NT Billing Factor	2016	60.333	84.080	97.065	80.344	69.608	70.108	55.117	52.523	61.136	70.917	67.878	59.955	829.064
171	Kootenai	NT Billing Factor	2017	60.649	84.418	97.402	80.648	70.794	70.443	55.414	52.825	61.486	71.278	68.229	60.292	833.878
172																
173	Lakeview	NT Billing Factor	2016	39.770	46.153	49.842	50.744	49.809	43.361	37.149	30.973	32.155	34.323	33.908	31.552	479.739
174	Lakeview	NT Billing Factor	2017	39.970	46.384	50.091	50.999	50.058	43.578	37.335	31.128	32.316	34.495	34.077	31.709	482.140
175																
176	Lewis	NT Billing Factor	2016	151.234	152.868	191.145	183.171	167.949	159.828	144.715	117.335	99.103	104.946	113.887	98.389	1,684.570
177	Lewis	NT Billing Factor	2017	151.595	153.211	191.576	183.563	168.256	160.177	145.041	117.619	99.341	105.206	114.169	98.629	1,688.383
178	Lewis	Short Distance Discount	2016	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-4.135
179	Lewis	Short Distance Discount	2017	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-0.345	-4.135
180																
181	Lost River	NT Billing Factor	2016	5.986	7.201	7.606	7.146	6.802	5.652	4.736	10.342	17.982	21.504	18.977	12.246	126.180
182	Lost River	NT Billing Factor	2017	6.026	7.245	7.651	7.146	6.802	5.652	4.736	10.440	18.122	21.654	19.125	12.380	126.979
183																
184	Lower Valley	NT Billing Factor	2016	104.674	124.208	146.731	153.618	145.717	115.147	90.699	82.144	87.012	86.472	79.049	72.765	1,288.236
185	Lower Valley	NT Billing Factor	2017	105.772	125.312	147.708	154.630	146.671	116.171	91.553	83.149	87.828	87.139	80.334	73.724	1,299.991
186																
187	Mason 1	NT Billing Factor	2016	9.330	12.370	16.856	18.292	12.845	13.169	10.824	9.110	6.922	6.587	6.786	6.511	129.602
188	Mason 2	NT Billing Factor	2017	9.351	12.398	16.894	18.335	12.875	13.199	10.849	9.131	6.937	6.603	6.802	6.526	129.900
189																
190	Mason 3	NT Billing Factor	2016	88.796	112.098	123.652	127.863	114.345	120.544	96.938	80.320	71.280	69.706	72.088	67.269	1,144.899
191	Mason 4	NT Billing Factor	2017	89.531	112.937	124.526	128.779	115.192	121.428	97.704	80.923	71.876	70.313	72.729	67.799	1,153.737
192																
193	McCleary	NT Billing Factor	2016	3.487	4.582	5.680	4.398	4.808	6.198	4.934	4.939	2.342	3.366	3.822	2.599	51.155
194	McCleary	NT Billing Factor	2017	3.494	4.590	5.689	4.405	4.817	6.208	4.943	4.949	2.348	3.375	3.833	2.605	51.256
195																
196	McMinnville	NT Billing Factor	2016	112.543	130.441	116.104	133.286	120.283	118.000	112.676	117.373	104.963	112.077	107.451	107.793	1,392.990
197	McMinnville	NT Billing Factor	2017	112.951	130.860	116.449	133.681	120.646	118.386	113.057	117.830	105.366	112.476	107.849	108.193	1,397.744
198																
199	Midstate	NT Billing Factor	2016	41.401	59.280	66.317	64.304	59.124	57.852	48.093	64.001	48.087	54.362	58.223	47.533	668.577
200	Midstate	NT Billing Factor	2017	41.452	59.354	66.399	64.383	57.157	57.926	48.162	64.147	48.203	54.508	58.367	47.626	667.684
201																
202	Milton	NT Billing Factor	2016	10.510	12.617	14.459	13.586	12.405	11.660	10.186	8.173	8.056	7.929	8.479	8.270	126.330
203	Milton	NT Billing Factor	2017	10.559	12.675	14.526	13.648	12.462	11.714	10.232	8.210	8.091	7.965	8.517	8.307	126.906

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
204																
205	Milton-Freewater	NT Billing Factor	2016	14.314	19.147	22.746	19.534	16.413	17.279	11.993	12.064	15.033	17.470	16.943	15.273	198.209
206	Milton-Freewater	NT Billing Factor	2017	14.327	19.164	22.767	19.551	16.427	17.296	12.004	12.075	15.046	17.485	16.959	15.287	198.388
207																
208	Minidoka	NT Billing Factor	2016	0.144	0.190	0.200	0.204	0.193	0.175	0.126	0.106	0.103	0.098	0.103	0.102	1.744
209	Minidoka	NT Billing Factor	2017	0.146	0.192	0.203	0.207	0.195	0.177	0.128	0.107	0.104	0.100	0.104	0.103	1.766
210																
211	Mission Valley	NT Billing Factor	2016	53.974	67.667	75.639	71.833	66.416	60.025	43.214	46.732	36.157	46.589	53.184	44.855	666.285
212	Mission Valley	NT Billing Factor	2017	54.426	68.235	76.276	72.436	66.974	60.528	43.574	47.120	36.459	46.980	53.628	45.229	671.865
213	Mission Valley	Short Distance Discount	2016	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-53.760
214	Mission Valley	Short Distance Discount	2017	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-4.480	-53.760
215																
216	Missoula	NT Billing Factor	2016	32.961	39.772	44.910	39.146	37.122	34.744	27.082	28.251	29.875	31.421	33.823	30.027	409.134
217	Missoula	NT Billing Factor	2017	33.286	40.164	45.351	39.532	37.489	35.089	27.352	28.533	30.176	31.737	34.163	30.326	413.198
218																
219	Modern	NT Billing Factor	2016	27.964	36.568	39.846	36.832	35.872	34.290	28.337	26.176	30.239	36.673	36.503	32.373	401.673
220	Modern	NT Billing Factor	2017	28.131	36.784	40.081	37.051	36.085	34.495	28.504	26.331	30.421	36.893	36.719	32.566	404.061
221																
222	Monmouth	NT Billing Factor	2016	10.462	12.525	12.246	14.018	13.549	11.423	10.047	7.954	7.837	9.127	9.381	8.628	127.197
223	Monmouth	NT Billing Factor	2017	10.517	12.591	12.309	14.090	13.620	11.483	10.099	7.996	7.879	9.175	9.430	8.674	127.863
224																
225	Nespelem	NT Billing Factor	2016	4.432	7.501	8.220	7.143	5.652	5.845	6.003	6.410	10.345	11.483	11.400	10.147	94.581
226	Nespelem	NT Billing Factor	2017	4.473	7.564	8.282	7.199	5.703	5.903	6.047	6.460	10.420	11.557	11.472	10.220	95.300
227																
228	NETL	NT Billing Factor	2016	0.478	0.741	-0.078	0.909	0.784	0.753	0.590	0.488	0.344	0.373	0.400	0.390	6.172
229	NETL	NT Billing Factor	2017	0.478	0.741	-0.078	0.909	0.784	0.753	0.590	0.488	0.344	0.373	0.400	0.390	6.172
230																
231	Northern Wasco	NT Billing Factor	2016	73.236	80.436	89.416	99.784	90.722	96.540	80.687	84.077	90.102	105.296	104.803	93.957	1,089.056
232	Northern Wasco	NT Billing Factor	2017	82.336	88.987	98.131	109.961	100.617	107.087	89.770	94.144	100.898	117.049	116.724	104.857	1,210.561
233																
234	Ohop	NT Billing Factor	2016	13.395	16.847	19.660	18.955	18.918	15.029	12.388	8.699	7.548	8.259	8.362	8.191	156.251
235	Ohop	NT Billing Factor	2017	13.433	16.886	19.702	18.994	18.960	15.065	12.421	8.731	7.584	8.298	8.401	8.224	156.699
236																
237	OPALCO	NT Billing Factor	2016	29.102	41.164	49.192	40.490	36.427	37.604	31.349	22.827	19.533	19.524	18.986	18.446	364.644
238	OPALCO	NT Billing Factor	2017	29.032	41.139	49.202	40.408	36.325	37.487	31.218	22.750	19.337	19.337	18.794	18.288	363.317
239																
240	Oregon Trail	NT Billing Factor	2016	80.124	95.430	106.979	99.900	92.930	92.951	90.037	86.046	92.599	101.921	99.014	81.918	1,119.849
241	Oregon Trail	NT Billing Factor	2017	81.058	96.524	108.200	101.031	93.983	94.029	91.089	87.062	93.713	103.140	100.178	82.888	1,132.895
242																
243	PAC	NT Billing Factor	2016	227.856	276.211	309.904	266.441	265.675	247.143	240.460	215.759	211.495	223.218	220.603	225.393	2,930.158
244	PAC	NT Billing Factor	2017	228.727	277.107	310.849	267.419	266.600	247.912	241.251	216.491	212.103	223.809	221.347	225.466	2,939.081

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
245																
246	Pacific	NT Billing Factor	2016	43.537	54.761	65.038	52.780	56.906	56.838	41.931	44.679	29.905	30.926	34.664	34.761	546.726
247	Pacific	NT Billing Factor	2017	43.766	55.007	65.300	52.992	57.140	57.098	42.141	44.951	30.131	31.168	34.932	35.003	549.629
248																
249	Parkland	NT Billing Factor	2016	20.073	23.685	26.087	24.179	24.958	22.082	18.090	14.046	12.681	13.789	13.565	13.280	226.515
250	Parkland	NT Billing Factor	2017	20.194	23.814	26.219	24.302	25.088	22.207	18.207	14.154	12.797	13.914	13.689	13.390	227.975
251																
252	Peninsula	NT Billing Factor	2016	102.023	117.129	133.778	129.551	126.400	108.800	90.935	68.781	62.980	69.673	70.955	67.172	1,148.177
253	Peninsula	NT Billing Factor	2017	103.156	118.271	134.993	130.710	127.564	109.869	91.900	69.683	63.894	70.663	71.952	68.085	1,160.740
254																
255	Plummer	NT Billing Factor	2016	4.768	5.421	6.119	6.180	5.388	5.902	4.804	3.556	3.135	3.663	4.086	3.568	56.590
256	Plummer	NT Billing Factor	2017	4.826	5.481	6.180	6.241	5.445	5.967	4.861	3.607	3.183	3.721	4.150	3.620	57.282
257																
258	PNGC															
259	Blachly-Lane	NT Billing Factor	2016	24.667	25.494	25.669	29.484	30.007	27.312	26.124	20.967	21.072	20.343	21.379	18.882	291.400
260	Blachly-Lane	NT Billing Factor	2017	24.667	25.494	25.669	29.484	30.007	27.312	26.124	20.967	21.072	20.343	21.379	18.882	291.400
261																
262	CEC	NT Billing Factor	2016	76.025	120.982	163.115	117.862	109.048	99.949	86.138	86.957	95.751	103.632	97.176	89.665	1,246.300
263	CEC	NT Billing Factor	2017	76.307	121.290	163.466	118.154	109.330	100.272	86.423	87.275	96.133	104.033	97.565	90.018	1,250.266
264																
265	Clearwater	NT Billing Factor	2016	28.905	36.587	41.316	37.842	36.464	31.627	28.411	22.800	21.229	23.868	23.976	20.243	353.268
266	Clearwater	NT Billing Factor	2017	28.967	36.652	41.377	37.907	36.525	31.688	28.473	22.854	21.288	23.932	24.039	20.294	353.996
267																
268	Consumers	NT Billing Factor	2016	40.283	43.377	43.974	50.379	48.698	44.619	39.656	30.491	27.756	36.863	40.214	33.231	479.541
269	Consumers	NT Billing Factor	2017	40.465	43.572	44.165	50.609	48.921	44.820	39.831	30.628	27.879	37.026	40.397	33.383	481.696
270																
271	Coos-Curry	NT Billing Factor	2016	43.262	57.860	-3.364	61.539	60.380	70.283	48.785	45.475	38.953	33.081	36.843	35.096	528.193
272	Coos-Curry	NT Billing Factor	2017	43.369	58.003	-3.372	61.692	60.530	70.456	48.906	45.589	39.049	33.162	36.934	35.184	529.502
273																
274	Douglas Elec	NT Billing Factor	2016	21.252	27.486	33.055	28.933	29.168	25.489	25.350	19.381	18.267	20.544	22.387	18.341	289.653
275	Douglas Elec	NT Billing Factor	2017	21.304	27.555	33.136	29.005	29.241	25.552	25.412	19.428	18.313	20.594	22.443	18.386	290.369
276																
277	Fall River	NT Billing Factor	2016	34.135	43.035	51.537	51.323	48.305	40.167	33.362	27.413	43.353	55.773	43.374	28.304	500.081
278	Fall River	NT Billing Factor	2017	34.455	43.365	51.856	51.653	48.621	40.477	33.663	27.674	43.634	56.079	43.659	28.572	503.708
279	Fall River	Short Distance Discount	2016	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-17.730
280	Fall River	Short Distance Discount	2017	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-1.478	-17.730
281																
282	Lane Electric	NT Billing Factor	2016	43.115	54.263	61.188	63.099	62.045	51.269	46.805	30.266	26.690	32.242	32.526	29.346	532.854
283	Lane Electric	NT Billing Factor	2017	43.220	54.378	61.309	63.232	62.172	51.374	46.904	30.359	26.768	32.324	32.606	29.422	534.068
284	Lane Electric	Short Distance Discount	2016	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.960
285	Lane Electric	Short Distance Discount	2017	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.080	-0.960

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

	(A)	(B)	(c)	(D)	(e)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Customer	**Product**	**Fiscal Year**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**Annual**
286																
287	Lincoln	NT Billing Factor	2016	15.366	19.756	21.718	19.106	17.488	16.986	12.123	11.925	9.853	11.038	11.084	10.230	176.673
288	Lincoln	NT Billing Factor	2017	15.366	19.756	21.718	19.106	17.488	16.986	12.123	11.925	9.853	11.038	11.084	10.230	176.673
289																
290	Northern Lights	NT Billing Factor	2016	47.420	63.447	70.855	61.107	50.524	52.186	41.104	36.342	36.343	39.415	40.374	38.254	577.371
291	Northern Lights	NT Billing Factor	2017	47.747	63.767	71.185	61.401	50.794	52.493	41.384	36.622	36.632	39.729	40.696	38.543	580.993
292	Northern Lights	Short Distance Discount	2016	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-11.293
293	Northern Lights	Short Distance Discount	2017	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-0.941	-11.293
294																
295	Okanogan Coop	NT Billing Factor	2016	7.556	11.029	13.649	13.872	10.638	8.468	6.720	5.942	5.293	6.242	6.329	5.177	100.915
296	Okanogan Coop	NT Billing Factor	2017	7.556	11.028	13.649	13.871	10.638	8.467	6.719	5.942	5.293	6.242	6.329	5.176	100.910
297																
298	Raft River	NT Billing Factor	2016	18.291	18.060	22.172	21.443	22.834	20.345	21.070	49.604	62.236	70.676	60.696	55.637	443.064
299	Raft River	NT Billing Factor	2017	18.450	18.325	22.438	21.719	23.103	20.605	21.239	49.833	62.494	70.954	60.984	55.916	446.060
300																
301	Umatilla	NT Billing Factor	2016	223.885	242.966	244.090	248.048	246.812	246.788	274.692	301.216	353.821	379.239	377.085	356.344	3,494.986
302	Umatilla	NT Billing Factor	2017	286.679	313.059	311.781	324.910	337.700	331.864	361.895	382.315	431.672	451.033	441.000	413.388	4,387.296
303																
304	West Oregon	NT Billing Factor	2016	10.879	12.359	13.251	12.997	13.255	12.320	11.013	9.050	7.407	7.588	7.651	7.295	125.065
305	West Oregon	NT Billing Factor	2017	10.879	12.359	13.251	12.997	13.255	12.320	11.013	9.050	7.407	7.588	7.651	7.295	125.065
306																
307	Port	NT Billing Factor	2016	20.508	17.627	17.119	16.561	16.504	16.829	16.862	17.043	18.674	20.737	20.165	18.016	216.645
308	Port	NT Billing Factor	2017	21.782	18.904	18.438	18.021	17.899	18.239	18.274	18.487	20.141	22.239	21.799	19.730	233.953
309																
310	Port Angeles	NT Billing Factor	2016	76.095	84.404	78.754	95.401	73.304	79.979	55.731	50.790	24.219	38.019	44.872	50.699	752.267
311	Port Angeles	NT Billing Factor	2017	76.192	84.517	78.859	95.539	73.387	80.074	55.756	50.801	24.151	37.985	44.862	50.711	752.834
312																
313	Ravalli County	NT Billing Factor	2016	18.074	22.319	25.175	21.646	20.796	18.579	13.844	16.167	15.721	16.909	18.368	14.307	221.905
314	Ravalli County	NT Billing Factor	2017	18.351	22.661	25.559	21.979	21.113	18.865	14.059	16.418	15.963	17.170	18.650	14.523	225.311
315																
316	Richland	NT Billing Factor	2016	114.329	141.024	165.420	153.462	130.042	125.225	108.796	109.671	132.930	167.061	164.395	144.569	1,656.924
317	Richland	NT Billing Factor	2017	115.722	142.739	167.433	155.376	131.666	126.789	110.154	111.041	134.587	169.145	166.446	146.373	1,677.471
318																
319	Riverside Electric	NT Billing Factor	2016	2.161	3.089	3.506	2.965	3.339	2.772	2.408	3.049	4.011	4.316	3.481	2.839	37.936
320	Riverside Electric	NT Billing Factor	2017	2.210	3.145	3.563	3.011	3.394	2.823	2.455	3.101	4.067	4.378	3.538	2.893	38.578
321																
322																
323	Rupert	NT Billing Factor	2016	10.654	14.021	15.190	15.046	14.580	12.295	11.038	8.958	9.907	10.845	10.155	9.481	142.170
324	Rupert	NT Billing Factor	2017	10.654	14.021	15.190	15.046	14.580	12.295	11.038	8.958	9.907	10.845	10.155	9.481	142.170

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

(A) Customer	(B) Product	(c) Fiscal Year	(D) OCT	(e) NOV	(F) DEC	(G) JAN	(H) FEB	(I) MAR	(J) APR	(K) MAY	(L) JUN	(M) JUL	(N) AUG	(O) SEP	(P) Annual
Salem	NT Billing Factor	2016	46.664	56.137	59.404	59.391	58.380	51.948	44.146	38.801	42.618	52.612	55.207	47.735	613.043
Salem	NT Billing Factor	2017	46.780	56.276	59.550	59.539	58.524	52.077	44.255	38.897	42.723	52.742	55.343	47.853	614.559
Salmon River	NT Billing Factor	2016	23.334	26.639	32.741	33.533	28.474	27.435	22.141	23.583	27.925	23.424	27.782	27.259	324.270
Salmon River	NT Billing Factor	2017	23.290	26.603	32.699	33.470	29.202	27.396	22.109	23.550	27.887	23.399	27.744	27.211	324.560
Skamania	NT Billing Factor	2016	17.314	21.741	31.816	27.595	22.335	23.552	20.208	16.409	13.785	16.457	15.919	15.627	242.758
Skamania	NT Billing Factor	2017	17.357	21.796	31.895	27.664	22.391	23.610	20.258	16.449	13.818	16.498	15.959	15.665	243.360
Soda Springs	NT Billing Factor	2016	3.136	4.033	4.739	4.033	3.933	3.782	3.309	3.099	3.285	3.498	3.275	3.124	43.246
Soda Springs	NT Billing Factor	2017	3.105	3.996	4.699	3.997	3.898	3.744	3.277	3.066	3.268	3.480	3.242	3.095	42.867
South Side	NT Billing Factor	2016	4.699	6.211	7.890	7.403	6.048	6.207	7.028	11.240	16.367	17.008	14.167	9.701	113.969
South Side	NT Billing Factor	2017	4.765	6.304	7.995	7.491	6.131	6.296	7.097	11.324	16.462	17.107	14.267	9.788	115.027
Steilacoom	NT Billing Factor	2016	6.593	8.747	9.309	8.459	8.680	7.377	6.215	4.671	3.792	4.311	4.471	4.372	76.997
Steilacoom	NT Billing Factor	2017	6.631	8.788	9.350	8.495	8.718	7.416	6.250	4.703	3.824	4.346	4.507	4.405	77.433
SUB	NT Billing Factor	2016	126.806	138.139	148.895	155.366	151.861	131.087	125.447	96.753	105.137	120.643	122.086	110.618	1,532.838
SUB	NT Billing Factor	2017	127.120	138.481	149.264	155.750	152.236	131.411	125.758	96.991	105.397	120.941	122.387	110.892	1,536.628
Sumas	NT Billing Factor	2016	4.026	4.479	4.828	4.308	4.738	4.527	4.353	4.157	3.719	4.196	4.143	3.801	51.275
Sumas	NT Billing Factor	2017	4.048	4.502	4.852	4.329	4.762	4.550	4.376	4.179	3.739	4.218	4.166	3.822	51.543
Surprise Valley	NT Billing Factor	2016	8.026	11.125	15.139	14.234	14.575	13.445	11.187	17.494	25.113	29.403	27.792	24.251	211.784
Surprise Valley	NT Billing Factor	2017	8.072	11.192	15.229	14.318	14.660	13.527	11.253	17.590	25.251	29.562	27.943	24.382	212.979
Tanner	NT Billing Factor	2016	14.353	16.671	18.445	17.400	16.785	15.851	12.403	10.489	10.336	11.921	10.927	10.025	165.606
Tanner	NT Billing Factor	2017	14.546	16.862	18.636	17.587	16.985	16.049	12.571	10.649	10.504	12.110	11.098	10.179	167.776
Tillamook	NT Billing Factor	2016	66.637	82.083	84.668	91.822	87.313	77.872	73.103	50.321	45.193	46.700	46.311	43.185	795.208
Tillamook	NT Billing Factor	2017	66.720	82.172	84.875	91.926	87.410	77.966	73.303	48.536	41.853	41.060	42.698	42.719	781.238
Tillamook	Short Distance Discount	2016	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-1.130
Tillamook	Short Distance Discount	2017	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-0.094	-1.130
Troy	NT Billing Factor	2016	2.694	3.228	4.073	3.493	3.002	3.191	2.358	1.973	1.747	2.362	2.274	2.008	32.403
Troy	NT Billing Factor	2017	2.741	3.277	4.124	3.536	3.044	3.236	2.396	2.014	1.788	2.414	2.325	2.050	32.945

Table 14
NT Load Forecast at Customer Peak
(Monthly Peak Megawatts)

(A) Customer	(B) Product	(c) Fiscal Year	(D) OCT	(e) NOV	(F) DEC	(G) JAN	(H) FEB	(I) MAR	(J) APR	(K) MAY	(L) JUN	(M) JUL	(N) AUG	(O) SEP	(P) Annual
UIUC	NT Billing Factor	2016	5.294	5.959	5.776	5.383	6.214	6.020	5.293	5.752	5.051	5.281	5.667	5.323	67.013
UIUC	NT Billing Factor	2017	5.316	5.980	5.796	5.403	6.237	6.040	5.313	5.772	5.071	5.301	5.687	5.343	67.259
United Electric	NT Billing Factor	2016	22.184	26.917	28.975	32.890	29.452	24.842	24.019	26.595	39.301	41.854	35.918	30.476	363.423
United Electric	NT Billing Factor	2017	22.607	27.356	29.408	33.330	29.880	25.265	24.434	27.020	39.752	42.324	36.393	30.933	368.702
USN Bangor	NT Billing Factor	2016	22.180	25.041	26.522	23.665	24.025	23.998	22.505	20.497	19.132	18.783	18.745	18.360	263.453
USN Bangor	NT Billing Factor	2017	22.186	25.047	26.528	23.671	24.031	24.004	22.511	20.503	19.137	18.789	18.751	18.366	263.524
USN Bremerton	NT Billing Factor	2016	31.534	27.622	37.410	36.127	34.951	37.642	36.950	29.269	32.345	34.163	24.002	24.233	386.248
USN Bremerton	NT Billing Factor	2017	31.534	27.622	37.410	36.127	34.951	37.642	36.950	29.269	32.345	34.163	24.002	24.233	386.248
USN Everett	NT Billing Factor	2016	1.506	1.736	1.745	1.736	1.690	1.701	1.460	1.509	1.059	0.997	0.984	1.403	17.526
USN Everett	NT Billing Factor	2017	1.506	1.736	1.745	1.736	1.690	1.701	1.460	1.509	1.059	0.997	0.984	1.403	17.526
Vera	NT Billing Factor	2016	33.654	39.795	42.519	39.159	40.619	38.610	29.729	28.534	32.058	40.961	39.453	36.271	441.362
Vera	NT Billing Factor	2017	33.968	40.167	42.919	39.525	40.998	38.971	30.005	28.800	32.358	41.346	39.824	36.608	445.489
Vigilante	NT Billing Factor	2016	17.652	22.134	25.151	22.006	22.974	18.766	15.458	22.517	33.752	31.716	28.757	23.809	284.692
Vigilante	NT Billing Factor	2017	17.836	22.369	25.418	22.240	23.218	18.965	15.620	22.742	34.083	32.031	29.043	24.051	287.616
Wahkiakum	NT Billing Factor	2016	6.365	8.540	10.570	9.749	4.944	3.506	3.524	2.274	1.490	1.965	2.318	2.572	57.817
Wahkiakum	NT Billing Factor	2017	6.365	8.540	10.570	9.749	4.944	3.506	3.524	2.274	1.490	1.965	2.318	2.572	57.817
Wasco	NT Billing Factor	2016	6.873	15.895	13.783	13.687	10.868	11.514	9.221	10.132	16.948	16.782	13.404	10.412	149.519
Wasco	NT Billing Factor	2017	6.930	16.035	13.896	13.802	10.955	11.609	9.302	10.223	17.109	16.936	13.531	10.503	150.831
Weiser	NT Billing Factor	2016	7.612	8.682	9.576	9.596	9.420	7.995	7.211	6.829	8.159	9.848	9.915	8.035	102.878
Weiser	NT Billing Factor	2017	7.694	8.763	9.658	9.676	9.504	8.074	7.289	6.903	8.236	9.929	9.998	8.113	103.837
Whatcom	NT Billing Factor	2016	27.448	28.059	28.000	26.546	27.851	21.973	27.186	26.708	27.530	28.092	27.952	28.053	325.398
Whatcom	NT Billing Factor	2017	27.540	28.152	28.093	26.635	27.943	22.047	27.279	26.798	27.623	28.186	28.045	28.147	326.488
WREC	NT Billing Factor	2016	102.531	104.858	112.213	108.308	104.264	106.430	93.308	85.396	104.835	101.017	100.730	99.704	1,223.594
WREC	NT Billing Factor	2017	104.929	107.716	113.924	111.389	105.963	107.940	94.140	86.156	106.870	101.923	101.636	101.681	1,244.267
Yakama	NT Billing Factor	2016	8.720	8.429	8.132	8.323	8.058	8.182	7.030	7.966	8.744	9.715	9.738	8.747	101.784
Yakama	NT Billing Factor	2017	8.720	8.430	8.133	8.324	8.059	8.183	7.031	7.966	8.745	9.715	9.738	8.747	101.791

Table 15
Utility Delivery Forecast
(Annual Average of Monthly Peak Megawatts)

	(A)	(B)	(C)	(D)	(E)
				Customer Peak (MW)	
	Transmission Customer	**Company Receiving Power**	**Point Name**	**2016**	**2017**
1	Ashland	Ashland	Mountain Avenue 12.5 kV	11.22	11.31
2	Ashland Total			11.22	11.31
3	Bandon	Bandon	Bandon 12.5 kV - BNDN	5.62	5.62
4			Langlois 12.5 kV - BNDN	0.48	0.48
5			Two Mile 12.5 kV	3.19	3.24
6	Bandon Total			9.29	9.34
7	Big Bend	Big Bend	Eagle Lake 13.8 kV	6.91	6.98
8			Glade 13.8 kV - BBEC	5.57	5.57
9			Ringold 13.8-BBEC	3.10	3.11
10			Scooteney 13.8-BBEC	2.38	2.38
11	Big Bend Total			17.96	18.03
12	Bonners Ferry	Bonners Ferry	Bonners Ferry 13.8-BNRF	2.46	2.46
13			Moyie Bnrs Fry 13.8 kV	3.94	3.94
14			North Bench 13.8-BNRF	3.45	3.45
15	Bonners Ferry Total			9.85	9.85
16	Cascade Locks	Cascade Locks	Acton 13.8 kV	0.46	0.46
17			Cascade Locks 13.8 kV	2.29	2.29
18	Cascade Locks Total			2.75	2.75
19	Central Lincoln	Central Lincoln	Mapleton 12.5 kV	1.65	1.65
20	Central Lincoln Total			1.65	1.65
21	Columbia REA	Columbia REA	Burbank 12.5 kV	2.13	2.14
22			Stateline 12.5 kV	1.30	1.31
23	Columbia REA Total			3.43	3.46
24	Coulee Dam	Coulee Dam	Coulee Dam 12 kV-COUL	2.59	2.64
25	Coulee Dam Total			2.59	2.64
26	Drain	Drain	Drain 12.5-Drain	2.36	2.37
27	Drain Total			2.36	2.37
28	Eatonville	Eatonville	Lynch Creek 12.5-EATV	4.31	4.32
29	Eatonville Total			4.31	4.32
30	Franklin County	Franklin County	Ringold 13.8-FCPD	3.56	3.57
31	Franklin County Total			3.56	3.57
32	Grant	Grant	Grand Coulee 12 kV	3.73	3.76
33	Grant Total			3.73	3.76
34	Hood River	Hood River	Hood River 12.5 kV	0.39	0.39
35			Parkdale 12.5-HOOD	5.31	5.33
36	Hood River Total			5.70	5.72
37	Lower Valley	Lower Valley	Swan Valley 12.5 kV	1.96	1.98
38	Lower Valley Total			1.96	1.98
39	Mason 3	Mason 3	Potlatch 12.5 kV	2.68	2.69
40	Mason 3 Total			2.68	2.69
41	Milton	Milton	Surprise Lake 12.5 kV	10.53	10.58
42	Milton Total			10.53	10.58
43	Minidoka	Minidoka	Minidoka 2.4 kV	0.15	0.15
44	Minidoka Total			0.15	0.15
45	Monmouth	Monmouth	Monmouth 12.5 kV - MONM	0.02	0.02
46	Monmouth Total			0.02	0.02

Table 15
Utility Delivery Forecast
(Annual Average of Monthly Peak Megawatts)

	(A)	(B)	(C)	(D)	(E)
				Customer Peak (MW)	
	Transmission Customer	**Company Receiving Power**	**Point Name**	**2016**	**2017**
47	Nespelem	Nespelem	Lone Pine 11.95 kV	0.53	0.53
48	Nespelem Total			0.53	0.53
49	NETL	NETL	Albany 12.5 kV-DOE	0.51	0.51
50	NETL Total			0.51	0.51
51	Ohop	Ohop	Lynch Creek 12.5-OHOP	1.26	1.26
52	Ohop Total			1.26	1.26
53	PAC	PAC	Albany PAC NT DP	6.47	6.50
54			Bandon PAC NT DP	1.65	1.70
55	PAC Total			8.12	8.19
56	PNGC	Blachly-Lane	Alderwood 12.5 kV	4.04	4.04
57			Walton 12.5 kV	0.52	0.52
58		Consumers	Burnt Woods 24.9 kV	1.51	1.51
59			Harrisburg 12.5 kV	3.27	3.28
60			Monmouth 12.5 kV - CP	1.62	1.63
61			North Butte 12.5 kV	1.19	1.19
62			Tumble Creek 24.9 kV	1.25	1.25
63		Coos-Curry	Bandon 12.5 kV - CCEC	-0.06	-0.06
64			Langlois 12.5 kV - CCEC	1.52	1.52
65			Norway 12.5 kV	1.92	1.93
66			Port Orford 12.5 kV	3.00	3.01
67		Douglas Elec	Drain 12.5-DEC	2.35	2.35
68			Gardiner 13.8 kV-DEC	0.47	0.47
69			Reedsport 12.5-DEC	0.55	0.55
70		Northern Lights	Bonners Ferry 13.8-NORT	2.75	2.75
71			Laclede 13.8 kV	5.33	5.33
72			Moyie 13.8 kV	0.85	0.85
73			North Bench 13.8-NORT	2.34	2.34
74			Sandpoint 13.8 kV	2.53	2.56
75			Selle 13.8 kV	4.72	4.71
76			Yaak 12.5 kV	0.86	0.87
77		Okanogan Coop	Winthrop 12.47 kV	7.24	7.24
78		Raft River	Grouse Creek 138 kV	0.55	0.55
79		West Oregon	Necanicum 12.5 kV	0.34	0.34
80	PNGC Total			50.67	50.75
81	Steilacoom	Steilacoom	Steilacoom 12.5 kV	6.42	6.45
82	Steilacoom Total			6.42	6.45
83	Surprise Valley	Surprise Valley	Davis Creek 12.5 kV	0.77	0.77
84	Surprise Valley Total			0.77	0.77
85	Tacoma Power	Tacoma Power	Ketron Island	0.06	0.06
86	Tacoma Power Total			0.06	0.06
87	Troy	Troy	Troy 13.8-Troy	2.70	2.75
88	Troy Total			2.70	2.75
89	**Grand Total**			**164.78**	**165.46**
90	*****PTP Customer Total**			**3.56**	**3.57**
91	**NT Customer Total**			**161.22**	**161.90**

Table 16.1
Transmission Credit Projections, Credits, and Interest at Current Rates, FY 2015–FY 2017

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
#	Request	Forecasted Transmission Credit			Forecasted Interest		
1		FY 2015	FY 2016	FY 2017	FY 2015	FY 2016	FY 2017
2	GI Request 1	$ 220	$ -	$ -	$ -	$ -	$ -
3	GI Request 2	$ 1,668	$ 1,668	$ 885	$ 107	$ 75	$ 13
4	GI Request 3	$ 6,034	$ 6,034	$ 6,034	$ 2,713	$ 2,593	$ 2,469
5	GI Request 4	$ 887	$ 887	$ 887	$ 217	$ 191	$ 163
6	GI Request 5	$ 984	$ 984	$ 984	$ 184	$ 220	$ 250
7	GI Request 6	$ 444	$ 155	$ -	$ 12	$ 1	$ -
8	GI Request 7	$ 1,100	$ 1,100	$ 1,100	$ 111	$ 109	$ 84
9	GI Request 8	$ 13,367	$ 11,588	$ -	$ 643	$ 165	$ -
10	GI Request 9	$ 665	$ 665	$ 665	$ 500	$ 493	$ 487
11	GI Request 10	$ 646	$ 646	$ 646	$ 55	$ 49	$ 27
12	GI Request 11	$ 646	$ 646	$ 646	$ 55	$ 49	$ 27
13	GI Request 12	$ 50	$ 50	$ 50	$ 4	$ 4	$ 2
14	GI Request 13	$ 1,143	$ 1,143	$ 1,143	$ 97	$ 86	$ 48
15	GI Request 14	$ 625	$ -	$ -	$ 6	$ -	$ -
16	GI Request 15	$ -	$ -	$ -	$ 240	$ 675	$ 1,180
17	GI Request 16	$ -	$ -	$ 208	$ -	$ 3	$ 5
18	GI Request 17	$ -	$ 3,554	$ 4,739	$ 824	$ 800	$ 662
19	GI Request 18	$ -	$ 1,331	$ 1,775	$ 111	$ 226	$ 195
20	GI Request 19	$ -	$ -	$ -	$ 10	$ 11	$ 11
21	GI Request 20	$ -	$ -	$ 104	$ 14	$ 71	$ 144
22	GI Request 21	$ -	$ -	$ 44	$ -	$ 74	$ 101
23	GI Request 22	$ -	$ -	$ -	$ -	$ 16	$ 175
24	GI Request 23	$ -	$ -	$ -	$ -	$ 146	$ 444
25	GI Request 24	$ -	$ -	$ -	$ -	$ 122	$ 323
26	COI Request 1	$ 1,354	$ 1,354	$ 1,354	$ 165	$ 108	$ 48
27	COI Request 2	$ 1,354	$ 1,354	$ 1,354	$ 165	$ 108	$ 48
28	COI Request 3	$ 528	$ 528	$ 528	$ 69	$ 48	$ 25
29	COI Request 4	$ 1,354	$ 1,354	$ 1,354	$ 178	$ 122	$ 64
30	COI Request 5	$ 1,002	$ 1,002	$ 1,002	$ 132	$ 90	$ 47
31	COI Request 6	$ 41	$ 41	$ 41	$ 5	$ 4	$ 2
32	COI Request 7	$ 677	$ 677	$ 677	$ 89	$ 62	$ 33
33	COI Request 8	$ 677	$ 677	$ 677	$ 89	$ 62	$ 33
34	COI Request 9	$ 203	$ 203	$ 203	$ 27	$ 18	$ 10
35	COI Request 10	$ 162	$ 162	$ 162	$ 21	$ 15	$ 8
36	**Total Network**	**$ 28,480**	**$ 30,452**	**$ 19,910**	**$ 5,903**	**$ 6,178**	**$ 6,810**
37	**Total COI**	**$ 7,350**	**$ 7,350**	**$ 7,350**	**$ 940**	**$ 636**	**$ 317**
38	**Total**	**$ 35,830**	**$ 37,802**	**$ 27,260**	**$ 6,843**	**$ 6,814**	**$ 7,128**

Table 16.2
Transmission Credit Projects, Credits, and Interest at Proposed Rates, FY 2015–FY2017

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
#	Request	Forecasted Transmission Credit			Forecasted Interest		
1		FY 2015	FY 2016	FY 2017	FY 2015	FY 2016	FY 2017
2	GI Request 1	$ 220	$ -	$ -	$ -	$ -	$ -
3	GI Request 2	$ 1,668	$ 1,677	$ 875	$ 107	$ 75	$ 12
4	GI Request 3	$ 6,034	$ 6,067	$ 6,067	$ 2,713	$ 2,592	$ 2,467
5	GI Request 4	$ 887	$ 892	$ 892	$ 217	$ 190	$ 163
6	GI Request 5	$ 984	$ 989	$ 989	$ 184	$ 219	$ 249
7	GI Request 6	$ 444	$ 155	$ -	$ 12	$ 1	$ -
8	GI Request 7	$ 1,100	$ 1,106	$ 1,106	$ 111	$ 109	$ 83
9	GI Request 8	$ 13,367	$ 11,587	$ -	$ 643	$ 164	$ -
10	GI Request 9	$ 665	$ 669	$ 669	$ 500	$ 493	$ 487
11	GI Request 10	$ 646	$ 650	$ 650	$ 55	$ 49	$ 27
12	GI Request 11	$ 646	$ 650	$ 650	$ 55	$ 49	$ 27
13	GI Request 12	$ 50	$ 50	$ 50	$ 4	$ 4	$ 2
14	GI Request 13	$ 1,143	$ 1,149	$ 1,149	$ 97	$ 86	$ 48
15	GI Request 14	$ 625	$ -	$ -	$ 6	$ -	$ -
16	GI Request 15	$ -	$ -	$ -	$ 240	$ 675	$ 1,180
17	GI Request 16	$ -	$ -	$ 208	$ -	$ 3	$ 5
18	GI Request 17	$ -	$ 3,573	$ 4,764	$ 824	$ 800	$ 660
19	GI Request 18	$ -	$ 1,338	$ 1,784	$ 111	$ 226	$ 194
20	GI Request 19	$ -	$ -	$ -	$ 10	$ 11	$ 11
21	GI Request 20	$ -	$ -	$ 104	$ 14	$ 71	$ 144
22	GI Request 21	$ -	$ -	$ 45	$ -	$ 74	$ 101
23	GI Request 22	$ -	$ -	$ -	$ -	$ 16	$ 175
24	GI Request 23	$ -	$ -	$ -	$ -	$ 146	$ 444
25	GI Request 24	$ -	$ -	$ -	$ -	$ 122	$ 323
26	COI Request 1	$ 1,354	$ 1,538	$ 1,538	$ 165	$ 103	$ 34
27	COI Request 2	$ 1,354	$ 1,538	$ 1,538	$ 165	$ 103	$ 34
28	COI Request 3	$ 528	$ 600	$ 600	$ 69	$ 46	$ 20
29	COI Request 4	$ 1,354	$ 1,538	$ 1,538	$ 178	$ 118	$ 50
30	COI Request 5	$ 1,002	$ 1,138	$ 1,138	$ 132	$ 87	$ 37
31	COI Request 6	$ 41	$ 46	$ 46	$ 5	$ 4	$ 2
32	COI Request 7	$ 677	$ 769	$ 769	$ 89	$ 59	$ 26
33	COI Request 8	$ 677	$ 769	$ 769	$ 89	$ 59	$ 26
34	COI Request 9	$ 203	$ 231	$ 231	$ 27	$ 18	$ 8
35	COI Request 10	$ 162	$ 185	$ 185	$ 21	$ 14	$ 6
36	**Total Network**	**$ 28,480**	**$ 30,552**	**$ 20,002**	**$ 5,903**	**$ 6,175**	**$ 6,803**
37	**Total COI**	**$ 7,350**	**$ 8,354**	**$ 8,354**	**$ 940**	**$ 610**	**$ 243**
38	**Total**	**$ 35,830**	**$ 38,906**	**$ 28,356**	**$ 6,843**	**$ 6,785**	**$ 7,046**

BONNEVILLE POWER ADMINISTRATION
DOE/BP 4626 • December 2014