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

BP-16 Rate Proceeding

Power Rates Study Documentation

BP-16-FS-BPA-01A

July 2015

2016 POWER RATES STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS AND SHORT FORMS

ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CIR	Capital Investment Review
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
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
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
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
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
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.
OMP	Oversupply Management Protocol
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability
PF	Priority Firm Power
PFIA	Projects Funded in Advance
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement

RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

DOCUMENTATION FOR THE 2016 POWER RATES STUDY

INTRODUCTION

The Documentation for the Power Rates Study (PRS) shows the details of the calculation of the proposed Power Rates.

Section 1: Introduction and Background contains an overview of the various models used in the rate development process and presents a flow chart showing the rate development process.

Section 2: Ratesetting Methodology and Process contains ratemaking tables that are the output of the Rate Analysis Model (RAM2016). The RAM2016 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. This group includes the RAM Core Excel-based model, a front-end and back-end database service, and separate modules for the computation of (1) TRM billing determinants, (2) Tier 2 rates, and (3) Resource Support Services (RSS) rates and revenues. The output tables of RAM2016 include billing determinants, which are based on power sales forecasts and associated outputs from the RHWM Process, as well as revenue requirements used in the PRS cost of service analysis (COSA). A series of tables show the initial allocation of the revenue requirement over the billing determinants. Next, tables present the rate design steps, incorporating statutory directives from section 7 of the Northwest Power Act. The final table shows the calculation of the resource cost contributions that appear in GRSP II.C.

Section 3: Rate Design documents the calculations of the Demand rate and Load Shaping rates, including the results of the Tier 2 and RSS modules of RAM. The Tier 2 module results include the Tier 2 rates and charges, billing determinants, rate design adjustments and remarketing associated with Tier 2, and non-Federal remarketing. The results of the RSS module include the rate design revenue credits and adjustments associated with RSS and the Resource Shaping Charge, which are fed into RAM Core for ratemaking purposes, as well as the associated RSS rates and charges, including the Resource Shaping Charge, the Transmission Scheduling Service charge, and the Grandfathered Generation Management Service charge. This section also includes a table that shows the steps to produce the Slice Billing Adjustments by customer, calculations for WECC and Peak assessment charges, and information on the five-year market purchases for Southeast Idaho transfer load service.

Section 4: The Revenue Forecast documents revenue forecasts at both current and proposed rates for the rate period, FY 2016–2017, and at current rates for the period immediately preceding the two-year rate period, FY 2015.

Section 5: Rate Schedules *No documentation*

Section 6: General Rate Schedule Provisions *No documentation*

Section 7: Slice *No documentation*

Section 8: Average System Costs documents monthly Residential Exchange Program loads and forecasted Average System Costs (ASCs).

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SECTION 1: INTRODUCTION AND BACKGROUND

RATE PROCESS MODELING

The components listed below, organized by rate proposal study, are the major analyses and computer models used in BPA's rate development process. Included is a brief description of the purpose of each component and how it fits in with the other components. See the flowchart on the page following this section for a picture of how the studies and models work together in the wholesale power rate development process.

POWER LOADS AND RESOURCES STUDY (BP-16-FS-BPA-03):

Federal System Load Obligation Forecast

The Federal system load obligation forecast estimates the firm energy load obligations that BPA expects to serve under its firm requirements power sales contracts (PSCs) and other BPA contract obligations. The Federal system firm requirements PSC obligation forecasts used in BPA's rate development process are the primary sources for (1) allocation factors used to apportion costs and (2) billing determinants used to calculate rates and revenues. These firm requirements PSC obligation forecasts are composed of customer group sales forecasts for consumer-owned utilities (COUs), Federal agencies, direct service industrial customers (DSIs), investor-owned utilities (IOUs), and other BPA PSC obligations, such as the U.S. Bureau of Reclamation. Individual COU and Federal agency loads are forecast by ALF, BPA's Agency Load Forecast model.

BPA also has contract obligations other than those served under BPA's firm requirements PSC obligations. These "other contract obligations" include contract sales to utilities and marketers and power commitments under the Columbia River Treaty. All these obligations are detailed in the Power Loads and Resources Study.

Hydro Regulation Study (HYDSIM)

The Federal system regulated hydro resource estimates are derived by BPA's hydro regulation model (HYDSIM), which estimates project generation for 80 water years (October 1928 through September 2008). BPA uses HYDSIM to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the PNW Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for the 80 water years of record. The hydro regulation study uses plant operating characteristics and conditions to determine energy production expected from each specific project. Physical characteristics of each project are provided by annual Pacific Northwest Coordination Agreement (PNCA) data submittals from regional utilities and government agencies involved in the coordination and operation of regional hydro projects. The HYDSIM model incorporates these operating characteristics along with power and non-power requirements to provide project-by-project monthly energy generation estimates for the Federal system regulated hydro projects for FY 2016-2017.

The HYDSIM studies incorporate the power and non-power operating requirements expected to be in effect during the rate period, including those described in the National Oceanic and

Atmospheric Administration (NOAA) Fisheries FCRPS Biological Opinion (BiOp) regarding salmon and steelhead, published May 5, 2008; the NOAA Fisheries FCRPS Supplemental BiOp, published May 20, 2010; the NOAA Fisheries FCRPS Supplemental BiOp, published January 17, 2014; the U.S. Fish and Wildlife Service (USFWS) FCRPS BiOp regarding bull trout, published December 20, 2000; the USFWS Libby BiOp regarding bull trout and Kootenai River white sturgeon, published February 18, 2006; relevant operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program; and other fish mitigation measures. Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation efficiency requirements. Additionally, HYDSIM uses hydro plant operating characteristics in combination with power and non-power requirements to simulate the coordinated operation of the hydro system. The Federal system hydro generation is used in the Federal system load-resource balance and is detailed in the Power Loads and Resources Study.

Federal System Load-Resource Balance

The Federal system load-resource balance completes BPA's loads and resources picture by comparing Federal system load obligations to Federal system resources. Federal system load obligations include BPA's firm requirements PSC obligations and other Federal contract obligations. Federal system resources include BPA's regulated and independent hydro resources under 1937 water conditions, contract purchases, and other non-hydro generating projects. The result of the Federal system resources less loads yields BPA's estimated Federal system monthly firm energy surplus or deficit, in average megawatts. Should the results indicate an energy deficit in the ratemaking process, augmentation purchases must be made to ensure an annual energy load-resource balance. The surplus/deficit calculation is performed for each year of the rate test period and is detailed in the Power Loads and Resources Study. Results from the Power Loads and Resources Study are used as input into the Power Risk and Market Price Study.

POWER REVENUE REQUIREMENT STUDY (BP-16-FS-BPA-02):

The Power Revenue Requirement Study develops BPA's generation revenue requirement for the rate test period. It uses repayment studies for the generation function to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and related generation assets. Repayment studies are conducted for each year of the rate test period and extend over the 50-year repayment period. The repayment studies establish a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all generation obligations within the required repayment period. Repayment study results are combined with forecasts of program spending to create the revenue requirement. The Power Revenue Requirement Study then determines whether a given set of annual revenues is sufficient to meet projected annual expenses and to cover a given set of long-term obligations when applied in accordance with the requirements of DOE Order RA 6120.2.

POWER RISK AND MARKET PRICE FORECAST STUDY (BP-16-FS-BPA-04):

Secondary Energy Revenue Forecast

The RevSim model is used to forecast secondary energy revenues, balancing power purchase expenses, and augmentation purchase expenses. After accounting for all loads and resources (including augmentation purchases), RevSim computes the monthly HLH and LLH quantities of secondary energy available to sell and power purchases needed to meet firm loads (balancing purchases) using hydro generation available under 80 years of historical streamflow conditions (1929-2008). Inputs are forecast loads, non-hydro resources, and hydro generation.

RevSim uses results from two hydro-regulation models, HYDSIM and the Hourly Operating and Scheduling Simulator (HOSS), plus load forecasts, to compute the available HLH and LLH surplus energy and deficits in the Federal hydro system under varying streamflow conditions. RevSim applies HLH and LLH monthly spot market prices supplied by the AURORAxmp model (see the Market Risk subsection below for a description of the AURORA model) to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. It also computes augmentation costs based on hydro generation data and AURORAxmp prices under 1937 hydro conditions. The Rate Analysis Model (RAM) and the Power Services Revenue Forecast (see Power Rates Study section below for descriptions of the RAM and the revenue forecast) both use the surplus energy revenues and balancing and augmentation power purchase expenses resulting from the Secondary Energy Revenue Forecast calculated in RevSim.

RevSim computes the 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payment. The amount of the 4(h)(10)(C) credit is determined by summing the costs of the operational impacts (power purchases) and the direct program expenses, Pisces computer software costs, and capital costs, and then multiplying the total cost by 0.223 (22.3 percent). The operational portion of the 4(h)(10)(C) credit is computed by applying the same AURORAxmp prices used for the calculation of secondary energy revenues to replacement power purchase amounts. The calculation of the replacement power purchases for 4(h)(10)(C) is described in the Power Loads and Resources Study.

Risk Analysis

RevSim in conjunction with AURORAxmp and Non-Operating Risk Model (NORM) are used to quantify BPA’s net revenue risk. RevSim estimates net revenue variability associated with various operating risks (load, resource, and natural gas price and 4(h)(10)(C) credit variations). NORM estimates the non-operating risks that are associated with uncertainties in the cost projections in the revenue requirement as well as a selection of revenue uncertainties not captured in RevSim and AURORAxmp. NORM also contains Accrual to Cash adjustments, which translates net revenue into cash flow. The results from RevSim and NORM are inputs into the ToolKit, which calculates the probability of BPA making all its scheduled Treasury payments on time and in full.

Risk Mitigation

The ToolKit Model is used to determine Treasury Payment Probability (TPP, the probability of BPA making all its planned Treasury payments during the rate period) given the net revenue risks quantified in RevSim and NORM and accounting for the impact of the risk mitigation tools. More specifically, ToolKit is used to assess the effects of various policies and risk mitigation measures on the level of year-end reserves available for risk that are attributable to Power Services.

Market Price

The market price run is used in the Power Rates Study for:

(a) the prices for surplus sales and balancing purchases in RAM2016,
(b) the Load Shaping rate,
(c) the Load Shaping True-up rate,
(d) the Resource Shaping rate,
(e) Resource Support Services rates,
(f) shaping the Demand rate,
(g) the PF Tier 2 Balancing Credit,
(h) the PF Unused RHWM Credit,
(i) Tier 1 PF Equivalent Rates,
(j) Melded PF Equivalent Rates,
(k) the Balancing Augmentation Credit, and
(l) NR rate design.

It is used in the Power Risk and Market Price Study for the risk analysis.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORAxmp. AURORAxmp is an economic fundamentals-based software application that models wholesale electric energy transactions in a competitive pricing system. AURORAxmp uses a demand forecast and supply cost information using WECC data to find an hourly market clearing price, or equivalently, the marginal cost of electric energy. To determine price in a given hour, AURORAxmp models the dispatch of electric generating resources in a least-cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource.

POWER RATES STUDY (BP-16-FS-BPA-01):

Rate Analysis Model (RAM2016)

RAM2016 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. RAM, a spreadsheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis (COSA) , Rate Directives, and Rate Design.

1. Cost of Service Analysis. This step ensures that BPA's proposed rates are consistent with cost of service principles and comply with BPA's statutory rate directives. The COSA Step determines the costs associated with the three resource pools (Federal base system (FBS), residential exchange, and new resources) used to serve sales load and then allocates those costs to the rate pools (Priority Firm Power (PF), Industrial Firm Power (IP), New Resource Firm Power (NR), and Firm Power Products and Services (FPS)). In addition, the COSA allocates the costs of conservation and other BPA programs to the rate pools.

2. Rate Directives. The Northwest Power Act requires that some rate adjustments be made after the initial allocation of costs to ensure that the rate levels for the individual rate pools (PF Preference, PF Exchange, IP, NR, and FPS) have the proper relationship to each other. The primary rate adjustments are described in sections 7(b) and 7(c) of the Northwest Power Act. The Rate Directives Step of RAM2016 performs these rate adjustments. The amount of PF Public rate protection and the levels of the IP and NR rate are set assuming a settlement of the legal issues associated with the Residential Exchange Program.

3. Rate Design. In the COSA and Rate Directive steps, costs are allocated to the various rate pools; upon completion of these steps, a certain amount of costs have been allocated to the PF Preference pool. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. The Tiered Rate Methodology (TRM) specifies a cost allocation methodology to PF Preference costs allocated in the COSA and Rate Directives steps. RAM2016 accomplishes this separate cost allocation through a process of mapping costs (including net residential exchange costs) and revenue credits (including IP and NR revenues, if any) to either the Tier 1 Composite, Non-Slice, Slice, or Tier 2 costs pools, and demonstrating by "proof" that cost allocations under the TRM and COSA/Rate Directives are equivalent in terms of aggregate costs recovered from PF Preference, PF Exchange, IP, and NR. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2016 using unique database keys.

   RAM2016 develops three rate designs: (1) a tiered rate design for the PFp rate, in which the Tier 1 rates are designed using customer charges and demand and energy rates; (2) a traditional demand and energy design for the PFp Melded rate, the IP rate, and the NR rate; and (3) a constant annual energy rate for each PFp Tier 2 rate and the PFx rates. RAM2016 designs rates for each rate pool. For the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied without further processing.

Resource Support Services Module of RAM

The Resource Support Services (RSS) module of RAM, a spreadsheet-based model, calculates the charges and rates applied to resources receiving RSS and related services. These services include Diurnal Flattening Service (DFS), Secondary Crediting Service (SCS), Forced Outage

Reserve (FORS), and grandfathered Generation Management Service (GMS). The RSS module of RAM will also calculate, as applicable, each customer's Resource Shaping Charge (RSC), Transmission Scheduling Service (TSS) and the Transmission Curtailment Management Service (TCMS) component of TSS (although the TCMS functionality in the RSS module is not currently implemented), the aggregate RSS and RSC revenue credits used in RAM Core (an Excel-based model, one of the computer applications in RAM), and the capacity obligations that will inform BPA generation planning and the Slice model. The RSS module is also the source of operating minimums, planned amounts, and FORS energy limits that are defined in the customer contracts. The RSS model calculates the above for non-Federal resources as well as Federal resources used as augmentation and Federal resources used to support the Tier 2 rate.

Tier 2 Module of RAM

The Tier 2 module of RAM, a spreadsheet-based model, calculates Tier 2 rates and the applicable Tier 2 revenue credits and adjustments used in RAM Core that are not already accounted for in the RSS module of RAM. This module also calculates customer remarketing credits for amounts of Tier 2 service, non-Federal resource DFS, and Resource Remarketing Service. It produces the aggregate revenue and cost data associated with remarketing between the Tier 2 cost pools used in the RAM Core calculation.

Revenue and Power Purchase Expense Forecast

The Revenue Forecast, section 4 of the Power Rates Study, presents BPA's expected level of revenue and power purchase expense for FY 2015-2017. FY 2015 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected power purchase expenses, which affect the sales of surplus energy, are also included. The revenue forecast documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR, if applicable) to projected billing determinants. These two revenue forecasts, one with current rates and the other with proposed rates, are used to demonstrate whether current rates will recover BPA's revenue requirement, and if not, whether proposed rates will recover the revenue requirement. The revenue test is described in the Power Revenue Requirement Study. The Revenue Forecast uses outputs from a number of sources to determine total revenues expected, to obtain short-term marketing revenues, balancing power purchase expenses, augmentation power purchase expenses, and 4(h)(10)(C) credits.

FY 2016-2017 Average System Cost (ASC) Forecasts

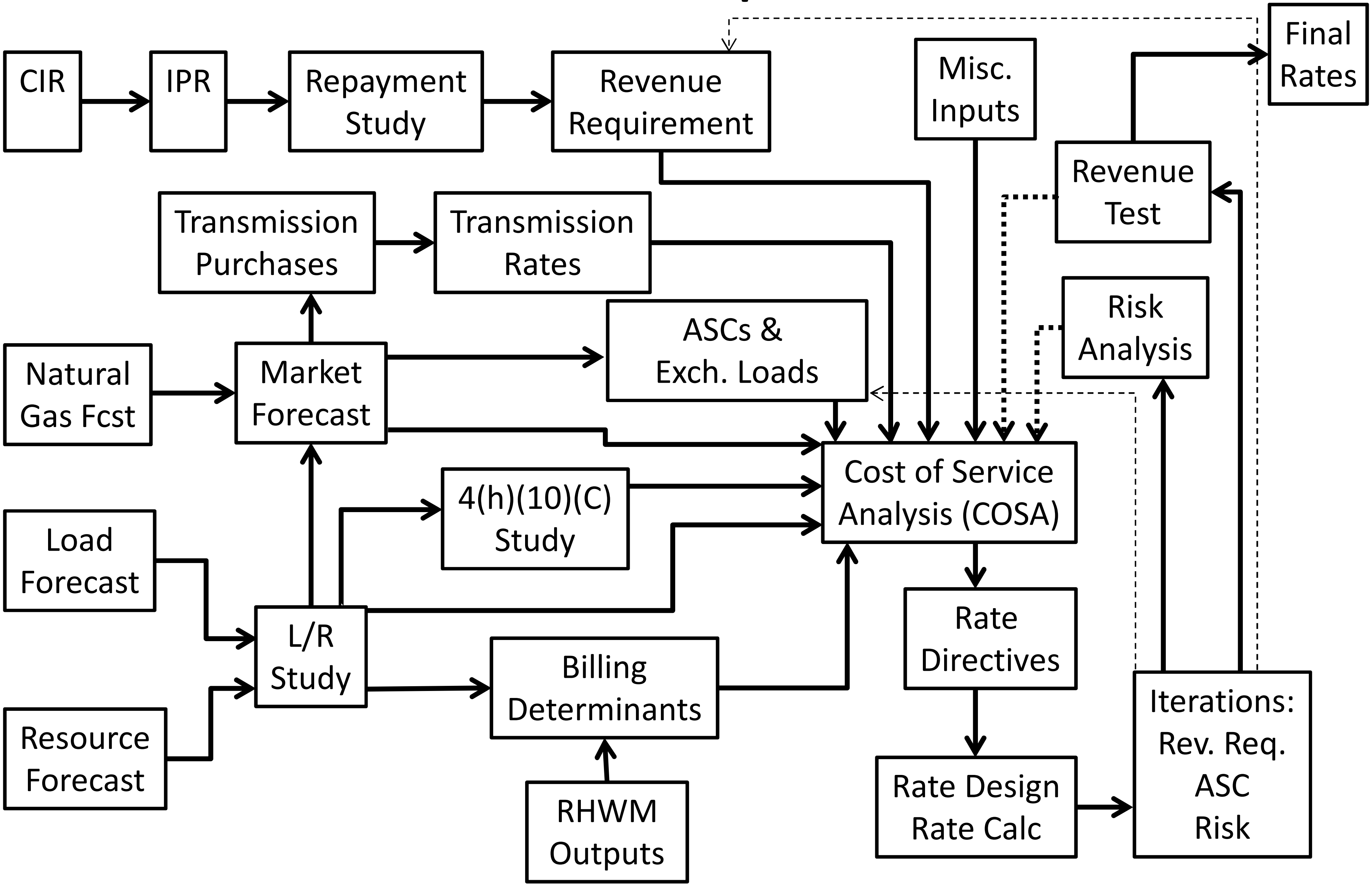
ASCs are used in determining the forecast of Residential Exchange Program (REP) benefits that exchanging utilities are entitled to during the rate period. For purposes of the BP-16 rates, BPA is using the ASC Reports published by BPA on July 23, 2015.

GENERATION INPUTS

Generation and Reserves Dispatch (GARD) Model

The variable costs associated with providing a quantity of reserves are assessed in the Generation and Reserves Dispatch (GARD) Model using inputs from the HYDSIM model, actual system data, and a pre-processing spreadsheet. The purpose of the GARD model is to calculate the variable costs incurred as a result of operating the FCRPS with the necessary reserves to maintain reliability and deploying those reserves to maintain load-resource balance within the BPA Balancing Authority Area. The GARD model analyzes variable costs in two general categories. The first category is the “stand ready” costs, those costs associated with making a project capable of providing reserves. The other includes “deployment costs,” those costs incurred when the system uses its reserve capability to actually deliver in response to a reserve need. The GARD model produces the following costs associated with standing ready: (1) energy shift, (2) efficiency change, (3) cycling losses, and (4) spill losses. GARD also calculates the following costs associated with deploying reserves: (1) response losses, (2) deployment cycling losses, and (3) deployment spill losses. After the GARD model is run, the megawatthour values for each month and HLH and LLH period of the 80 water year set are used by RevSim.

Power Rate Development Process



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SECTION 2: RATESETTING METHODOLOGY AND PROCESS

Description of Ratemaking Tables

Table 2.1.1
Disaggregated Load Input Data (RDI 01)
The "Loads" worksheet is the input site where disaggregated load data enters the model. The worksheet load data is displayed in average annual form as well as monthly diurnal form. Table 2.1.1 load data is displayed in average annual form. Energy values are in MWh.

Table 2.1.2
Disaggregated Resource Input Data (RDI 02)
The "Resources" worksheet is the input site where disaggregated resource data enters the model. The worksheet resource data is displayed in average annual form as well as monthly diurnal form. Table 2.1.2 resource data is displayed in average annual form. Energy values are in MWh.

Table 2.1.3
Residential Exchange Summary (RDI 03)
Worksheet displays the utilities that are forecast to be active in the REP with their average system costs and loads. Worksheet calculates the gross cost of exchange resources.

Table 2.2.1
Power Sales and Resources (EAF 01)
Worksheet aggregates the disaggregated sales and resource date from their input worksheets.

Table 2.2.2
Aggregated Loads and Resources (EAF 02)
Worksheet added transmission losses to power sales from the previous worksheet and performs an annual energy loads and resource balance.

Table 2.2.3
Calculation of Energy Allocation Factors (EAF 03)
Worksheet displays the energy loads and resource balance from the previous worksheet and also calculates several sets of Energy Allocation Factors (EAFs). The EAFs measure the relative use of the different types of resources to serve the different types of loads in the COSA ratemaking step. In addition, EAFs are used to reallocate costs among load types to comport with specific Rate Directive steps.

Table 2.3.1
Disaggregated Costs and Credits (COSA 01)
Worksheet is the input site where disaggregated revenue requirement cost data as well as revenue credit data enters the model. Each line item in the worksheet is associated with aggregation keys that are used in the model to build the COSA and TRM cost tables used in the subsequent ratemaking calculations.

Table 2.3.2
Cost Pool Aggregation (COSA 02)
Worksheet aggregates the revenue requirement data from the previous worksheet into the COSA cost categories: FBS costs, New Resource costs, Residential Exchange Program costs, Conservation costs, BPA Program costs and Power Transmission costs. Balancing power purchase cost and system augmentation purchase cost are calculated in the model as is the Residential Exchange Program costs.

Table 2.3.3
Computation of Low Density and Irrigation Rate Discount Costs (COSA 03)
Worksheet calculates the foregone revenue due to the Low Density Discount and the Irrigation Rate Discount. The foregone revenue must be added to the power revenue requirement as a cost to be recovered from PF rates. A macro is used to iterate the costs of the LDD/IRD with the TRM rates so that the LDD/IRD costs are calculated with the current power rates.

Table 2.3.4.1
Allocation of FBS Costs and LDD/IRD Costs (COSA 04-1)
Worksheet allocates FBS costs as directed by section 7(b) of the Northwest Power Act. Worksheet allocates LDD/IRD costs due to the foregone revenue associated with the LDD and IRD rate discounts are allocated to PF load.

Table 2.3.4.2
Allocation of New Resource Costs and Exchange Resource Costs (COSA 04-2)
Worksheet allocates New Resource costs as directed by sections 7(b) and 7(f) of the Northwest Power Act. Worksheet functionalizes Exchange resource costs between power and transmission before allocating the power portion as directed by sections 7(b) and 7(f) of the Northwest Power Act.

Table 2.3.4.3
Allocation of Conservation, BPA Program and Transmission Costs (COSA 04-5)
Worksheet allocates Conservation costs, BPA Program costs and Transmission costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.5
Allocation of Costs Summary (COSA 05)
Worksheet displays the dollar amounts in the seven COSA cost categories or cost pools and the initial allocation of those costs to the four COSA rate pools.

Table 2.3.6
General Revenue Credits (COSA 06)
Worksheet displays and aggregates the revenue credits from the disaggregated cost worksheet above.

Table 2.3.7.1
Revenue Credits Allocated to FBS Costs (COSA 07-1)

Worksheet allocates FBS related revenue credits as directed by section 7(b) of the Northwest Power Act.

Table 2.3.7.2
Allocation of Transmission Related Revenue Credits (COSA 07-2)
Worksheet allocates revenue credits associated with transmission costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.3
Revenue Credits Allocated to New Resource Costs (COSA 07-3)
Worksheet allocates New Resource related revenue credits as directed by sections 7(b) and 7(f) of the Northwest Power Act.

Table 2.3.7.4
Revenue Credits Allocated to Conservation Costs (COSA 07-4)
Worksheet allocates revenue credits associated with Conservation costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.5
Allocation of Generation Input Related Revenue Credits (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.6
Allocation of Non-Federal RSS/RCS Related Revenue Credits (COSA 07-6)
Worksheet allocates revenue credits associated with non-federal RSS/RCS as directed by section 7(g) of the Northwest Power Act.

Table 2.3.8
Calculation and Allocation of Secondary Revenue Credit (COSA 08)
Worksheet calculates the secondary revenue credit for the rate test period. The secondary revenue credit is allocated to loads that recover FBS and New Resource costs.

Table 2.3.9
Calculation and Allocation of FPS Revenue Deficiency Delta (COSA 09)
Worksheet calculates the firm surplus sale revenue (surplus)/shortfall. The generation revenue requirement costs allocated to FPS sales are reduced by the excess revenue credit allocated to FPS sales in the previous worksheet. The resulting costs are compared with the revenues recovered from FPS sales, resulting in a revenue deficit. This revenue deficit is allocated based on the service provided by the FBS and NR resources to these rate pools.

Table 2.3.10
Calculation of Initial Allocation Power Rates (COSA 10)
Worksheet uses the cost and revenue credit allocations at this point in the rate modeling when the COSA allocations have been completed and before the Rate Directive steps to calculate initial rates.

Table 2.4.1
Calculation of the DSI Value of Reserves and Net Industrial Margin (RDS 01)
Worksheet is the input site where data used to calculate the Direct Service Industry (DSI) value of reserves (VOR), Industrial Margin and Net Industrial Margin is input into the model. Worksheet also calculates the Net Industrial Margin to be used in the calculation of the IP rates.

Table 2.4.2
Calculate Energy Rate Scalars First IP-PF Link Calculation (RDS 02)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resultant energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.3
Calculate Monthly Energy Rates Used in First IP - PF Link Calculation (RDS 03)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape to the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.4
Calculation of First IP-PF Link Delta (RDS 04)
Worksheet uses shaped energy rates from the previous worksheet to calculate the first IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate," the load-weighted PF and NR rates. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period

Table 2.4.5
Allocation of First IP-PF Link delta and Recalculation of Rates (RDS 05)
Worksheet reallocates the first IP-PF link delta from the previous worksheet. The delta amount is reallocated from IP to all other loads (7b and 7f loads associated with PF Preference, PF Exchange, and NR).

Table 2.4.6
Calculation of the DSI Floor Rate (RDS 06)
The IP-83 rates are applied to the current DSI test period billing determinants to determine an average rate. Adjustments are made for Transmission, Exchange Cost, and Deferral to yield the DSI floor rate.

Table 2.4.7
DSI Floor Rate Test 1 (RDS 07)

A test is conducted comparing the IP rate at this stage in the rate-making process to the floor rate established above.

Table 2.4.8
Calculation of IOU and COU Base Exchange Rates (RDS 08)
Worksheet calculates the Base Exchange rates for IOU and COU exchanging utilities. The IOU Base Exchange rate is the unbifurcated PF rate with transmission costs added. The COU Base Exchange rate differs in that it is calculated without Tier 2 costs and loads.

Table 2.4.9
Calculation of IOU REP Benefits in Rates (RDS 09)
Worksheet calculates the annual IOU REP Benefits to be recovered in power rates.

Table 2.4.10
Calculation of REP Unconstrained Benefits (RDS 10)
Worksheet calculates the REP benefits assuming no PF Public rate protection. The IOU and COU Base PF Exchange rates are subtracted from each IOU and COU individual utility average system cost and that difference is multiplied by the utility's exchangeable load to yield its Unconstrained Benefit.

Table 2.4.11
Calculation of Utility Specific PF Exchange Rates and REP Benefits (RDS 11)
Worksheet calculates utility specific PF Exchange rates by adding a utility specific REP Settlement Charge to the Base Exchange rate. The IOU REP Settlement Charges are sized to collect the difference between the Unconstrained Benefits for the IOUs and the REP Settlement Benefit for the IOUs. This amount is the PF Public rate protection provided by the IOU Exchangers. The IOU Settlement Charges are computed for each utility by allocating this rate protection amount among the IOUs according to the relative size of their share of the Unconstrained Benefits. COUs Settlement Charges are computed by imputing an amount of "protection" equivalent to the IOU Settlement.

Table 2.4.12
IOU Reallocation Balances (RDS 12)
Table 2.4.11 performs a reallocation of benefits between the IOUs to account for differential outstanding Lookback balances at the time of the REP Settlement. The procedure for the reallocation is included in section 6.2 of the Settlement Agreement. This table shows the outstanding balances each IOU is obligated to repay to other IOUs, if any, for the full term of the Regional Dialogue contracts. Provided that each utility has sufficient benefit amounts prior to reallocation, these amounts (and scheduled future amounts) will not change. However, if a particular utility has insufficient benefits in any one rate period to pay down its reallocation obligation, the scheduled payment amounts will be recalculated.

Table 2.4.13
Allocation of the Increased PF Exchange Costs Due to Settlement (RDS 13)

The difference between the Unconstrained Benefits and the REP Settlement benefits is allocated to the Priority Firm Exchange loads and away from the PF Preference loads. Average power rates are calculated after this reallocation of costs.

Table 2.4.14
Calculation of PF, IP and NR Contribution to Net REP Benefit Costs (RDS 14)
At this point in the REP Settlement rate modeling, the cost of providing IOU and COU Net REP Benefits is assumed to be spread pro-rata by load to all PF Public, IP, and NR load. A reallocation adjustment is performed to make the REP Benefit cost contribution of the various rate pools comport with the Net REP Exchange cost contribution present in the WP-10 rate proceeding. The ratio of BP-12 to WP-10 net benefits is used as a factor applied to scale down (or up) the supplemental surcharge from its WP-10 level, and apply this surcharge to IP and NR load to determine the amount of net REP dollars which should be applied to IP and NR loads..

Table 2.4.15
Reallocate Rate Protection Provided by IP and NR Rates (RDS 15)
Worksheet reallocates the rate protection amount provided by the IP and NR rates from the previous worksheet to the PF Public rate pool. Rates are then computed.

Table 2.4.16
Annual PF and IP scalar under Settlement (RDS 16)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resultant energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.17
Monthly PF and IP rates under Settlement (RDS 17)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape to the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.18
IP_PF Link (RDS 18)
Worksheet uses shaped energy rates from previous worksheet to calculate the IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate," the load-weighted PF and NR rates. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period

Table 2.4.19
Reallocation of IP-PF Link Delta (RDS 19)

Worksheet Reallocates IP-PF Link Delta dollars from IP to PF preference and NR loads and recalculates average power rates.

Table 2.4.20
REP Benefit Reconciliation (RDS 20)
This worksheet does a comparison of calculated REP benefits to the cost/revenue allocations from the COSA step.

Table 2.5.1
Cost Aggregation under Tiered Rate Methodology (DS 01)
Worksheet aggregates costs and credits to be used in the TRM ratemaking. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, and cost and credit line items internally computed in RAM2012. For each cost pool under TRM, costs are conveniently grouped according to their COSA classification.

Table 2.5.2
Calculation of Unused RHWM (net) Credit (DS 02)
Worksheet calculates the $/MWh value for unused Rate Period High Water Mark. That value is used to determine the reallocation adjustment to distribute costs between the Composite and Non-Slice cost pools properly.

Table 2.5.3
Calculation of Slice Return of Network Losses Adjustment (DS 03)
Worksheet calculates the value of power associated with Non-slice network losses, such that these costs can explicitly be included in the Nonslice cost pool. This leaves only system losses for which all Composite customers pay (regardless of product subscription) in the Composite cost pool, and properly accounts for Customer return of Slice-Resource losses. That value is used to determine the reallocation credit that will shift costs between the Composite and Non-Slice TRM cost pools.

Table 2.5.4
Calculation of Load Shaping and Demand Revenues (DS 04)
Worksheet calculates the Load Shaping and Demand revenues under the TRM rate design. These revenues are used as a credit against the costs in the Non-Slice rate pool.

Table 2.5.5
Calculation of PF Public Rates under Tiered Rate Methodology (DS 05)
Worksheet applies the costs, revenue credits and inter-rate-pool reallocations to the Composite, Non-Slice, Slice and Tier 2 TRM rate pools to produce TRM rates. The TRM rates are in the form of monthly $/percent TOCA.

Table 2.5.6.1
Calculation of Net REP Ratemaking and Recovery Demonstration (DS 06-1)

Worksheet applies all power costs and revenue credits to the PF Public rate pool. The IP revenues are calculated with a macro to arrive at the proper relationship between the PFp rate and the IP rate. The net REP benefits are used in the calculations. The worksheet demonstrates that the PFp rate using the net REP benefits is identical to the PFp calculated with BPA's standard gross REP methodology.

Table 2.5.6.2
TRM PFp Revenues Equal to Non-TRM PFp Revenues (DS 06-2)
Worksheet demonstrates that the TRM revenues from Table 2.5.5 are equal to the non-TRM revenues from Table 2.5.6.1.

Table 2.5.7.1
Calculation of Priority Firm Public Tier 1 Rate Equivalent Components (DS 07-1)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a Tier 1 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 PF revenue requirement.

Table 2.5.7.2
Calculation of Priority Firm Public Melded Rate Equivalent Components (DS 07-2)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a melded Tier 1 and Tier 2 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 and Tier 2 PF revenue requirement. These monthly energy PF rates are necessary to calculate the Industrial Firm Power rates.

Table 2.5.7.3
Calculation of Industrial Firm Power Rate Components (DS 07-3)
Worksheet calculates the Industrial Firm Power (IP) rate monthly energy and demand components. The IP rate is a formula rate derived from the "applicable wholesale rate." In this rate proceeding, with no NR load, the applicable wholesale rate is the melded PF Public rate. The monthly IP energy rates are set equal to the melded PF rate, plus the DSI value of reserve (VOR), plus the Industrial Margin, plus the Settlement Charge.

Table 2.5.7.4
Calculation of New Resource Rate Components (DS 07-4)
Worksheet calculates the energy and demand components for the New Resources (NR) rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the NR revenue requirement.

Table 2.5.7.5
Calculation of the Load Shaping True-up Rate (DS 07-5)
Worksheet calculates the Load Shaping True-up rate by comparing the non-slice Tier 1 market energy revenue (the non-slice Tier 1 loads times the market rates) with the non-slice Tier 1 energy revenue at Tier 1 rates. The difference in the form of a $/MWh is the Load Shaping True-up rate.

Table 2.5.8.1
Allocated Costs and Unit Costs, Priority Firm Power Rates (DS 08-1)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Public Power and Priority Firm Exchange Power. A percent contribution to the final Priority Firm Preference Power rate and Priority Firm Exchange Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.8.2
Allocated Costs and Unit Costs, Industrial Firm Power (DS 08-2)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Industrial Firm Power. A percent contribution to the final Industrial Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.8.3
Allocated Costs and Unit Costs, New Resource Firm Power (DS 08-3)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with New Resource Firm Power. A percent contribution to the final New Resource Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.8.4
Resource Cost Contribution (DS 08-4)
Table provides a summary of the percentages of each resource pool, FBS, Residential Exchange, and New Resources, used in ratemaking to serve each of the rate pools, PF, IP, NR, and FPS.

Rate Data Input
Disaggregated Loads
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
4				2016	2017
5	Preference			60,664,170	60,914,697
6		Block		15,670,230	16,141,481
7		Slice		16,341,017	16,056,544
8		Load Following		28,054,970	28,022,223
9		Tier 2 (Block)		597,953	694,449
10	Industrial			800,387	798,202
11		Smelter		658,800	657,000
12		Other Industrial		141,587	141,202
13	New Resource			9	9
14	Firm Power and Services			6,909,347	6,800,324
15		Intraregional Transfer		703,015	702,788
16			WNP3	785,139	785,138
17			Dittmer Station Service	82,895	82,668
26		FBS Obligation		5,911,317	5,824,749
27			Canadian Entitlement	4,140,141	4,098,372
28			USBR Pump Load	1,611,833	1,611,229
29			Hungry Horse	63,014	46,081
30			Upper Baker	11,228	11,228
31			Non-Treaty Storage	101,143	103,224
32			Libby Coordination	0	0
37		Seasonal or Capacity Exchange		295,014	272,788
38			Riverside Capacity	19,620	0
39			Riverside Seasonal	0	0
40			Pasadena Capacity	0	0
41			Pasadena Seasonal	0	0
42			PG&E	229,711	227,760
43			Intertie Losses	7,480	6,833
44			PacifiCorp	38,202	38,195

Rate Data Input
Disaggregated Resources
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
5				2016	2017
6	Hydro			59,739,015	60,254,069
7		Regulated		55,432,171	55,959,205
8		Independent		3,099,425	3,095,775
9			Cowlitz Falls	232,671	232,343
10			Idaho Falls	124,397	123,900
11			PreAct	2,742,357	2,739,532
19		Hydro Other		1,207,419	1,199,089
20			Canadian Entitlement	1,207,419	1,199,089
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			9,960,379	8,445,246
31		Water		23,102	23,039
32			Dworshak/Clearwater Small Hydropower	23,102	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,442,800	8,023,800
43			Columbia Generating Station	9,442,800	8,023,800
53		Wind		398,922	398,379
54			Foote Creek 1	34,886	34,833
55			Foote Creek 2	0	0
56			Foote Creek 4	38,260	38,202
57			Stateline Wind Project	181,383	181,201
58			Condon Wind Project	84,682	84,511
59			Klondike I	59,711	59,633
64		Renewable		95,555	27
65			Georgia-Pacific Paper (Wauna)	95,528	0
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	27	27
68			White Bluffs Solar	0	0

Rate Data Input
Disaggregated Resources
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
5				2016	2017
75	Contracts			705,541	578,040
76		Imports		383,659	313,889
77			Riverside Exchange Energy	64,341	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,784	8,760
80			Slice Return of Losses	310,535	305,129
87		Seasonal or Capacity Exchange		321,882	264,151
88			Riverside Capacity	19,980	0
89			Riverside Seasonal	37,426	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E	226,273	225,956
93			PacifiCorp	38,203	38,195
98		Tier2		0	0
99			Short Term	0	0
100			Load Growth	0	0
101			Vintage 1	0	0
102			Vintage 2	0	0
103			Vintage 3	0	0
109	Augmentation and Balancing			126,817	737,024
110		System Augmentation		0	610,371
111		Balancing		0	0
112		Tier 1 Resources		126,817	126,654
113			Klondike III	124,614	124,451
114			Rocky Brook	2,203	2,203
115					
116	Transmission Losses			(2,094,793)	(2,079,427)

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2015 - September 2017

	B	D		E	
7	**Exchange ASCs ($/MWh)**	**2016**		**2017**	
8					
9	Avista Corporation	$	50.87	$	50.87
10	Idaho Power Company	$	59.02	$	59.02
11	NorthWestern Energy, LLC	$	79.24	$	79.24
12	PacifiCorp	$	76.42	$	76.42
13	Portland General Electric Company	$	71.14	$	71.14
14	Puget Sound Energy, Inc.	$	67.09	$	67.09
15	Clark Public Utilities	$	50.95	$	50.95
17	Snohomish County PUD No 1	$	49.59	$	49.85
18					
19	**Exchange Loads (GWh)**	**2016**		**2017**	
20					
21	Avista Corporation	3,897		3,897	
22	Idaho Power Company	6,763		6,763	
23	NorthWestern Energy, LLC	679		679	
24	PacifiCorp	9,006		9,006	
25	Portland General Electric Company	8,600		8,600	
26	Puget Sound Energy, Inc.	11,617		11,617	
27	Clark Public Utilities	2,388		2,377	
29	Snohomish County PUD No 1	3,784		3,848	
30		46,734		46,788	
31					
32	**Exchange Resource Cost ($000)**	**2016**		**2017**	
33					
34	Avista Corporation	$	198,258	$	198,258
35	Idaho Power Company	$	399,164	$	399,164
36	NorthWestern Energy, LLC	$	53,788	$	53,788
37	PacifiCorp	$	688,223	$	688,223
38	Portland General Electric Company	$	611,802	$	611,803
39	Puget Sound Energy, Inc.	$	779,414	$	779,414
40	Clark Public Utilities	$	121,653	$	121,133
42	Snohomish County PUD No 1	$	187,658	$	191,823
43		$	3,039,959	$	3,043,605

Energy Allocation Factor
Power Sales and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	E	F
4			**2016**	**2017**
5	**Sales**			
6	Public			
7		Load Following	3,194	3,199
8		Tier 2 (block)	68	79
9		Slice (output energy)	1,860	1,833
10		Block	1,784	1,843
12	Exports			
13		BC Hydro (Cdn Entitlement)	471	468
14		Non-Treaty Storage	12	12
15		Libby Coordination	0	0
16		Pasadena Capacity	0.0	0
17		Pasadena Seasonal	0.0	0
18		Riverside Capacity	2	0
19		Riverside Seasonal	0	0
20		PacifiCorp	4	4
21		PG&E	26	26
22		Intertie Losses	1	1
23	Intra-regional Transfers			
24		Avista (WNP#3 Settle.)	89	90
25		Dittmer/Substation Sale	9	9
26	Other Loads			
27		USBR Pump Load	183	184
28		Hungry Horse	7	5
29		Upper Baker	1	1
30		Direct Service Industries	91	91
31		New Resource	0.0	0
32	Total Firm Obligations		**7,805**	**7,845**
33				
34	**Resources**			
35	Hydro			
36		Regulated	6,311	6,388
37		Independent		
38		Cowlitz Falls	26	27
39		Idaho Falls	14	14
40		PreAct	312	313
41		Non-Fed CER (Canada)	137	137
42		Libby Coordination	0	0
43	Other Hydro Resources			
44				

Energy Allocation Factor
Power Sales and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	E	F
4			**2016**	**2017**
45	Combustion Turbines			
46	Renewables			
47		Foote Creek 1	4	4
48		Foote Creek 2	0	0
49		Foote Creek 4	4	4
50		Stateline Wind Project	21	21
51		Condon Wind Project	10	10
52		Klondike I	7	7
53		Georgia-Pacific Paper (Wauna)	11	0
54		Klondike III	14	14
55		Fourmile Hill Geothermal	0	0
56		Ashland Solar Project	0	0
57		White Bluffs Solar	0	0
58	Cogeneration			
59	Imports			
60		Riverside Exchange Energy	7	0
61		Pasadena Exchange Energy	0	0
62		BC Hydro Power Purchase	1	1
63		Riverside Capacity	2	0
64		Riverside Seasonal	4	0
65		Pasadena Capacity	0	0
66		Pasadena Seasonal	0	0
67		Slice Losses Return	35	35
68	Regional Transfers (In)			
69		PG&E	26	26
70		PacifiCorp	4	4
71	Large Thermal		1,075	916
72	Non-Utility Generation			
73		Dworshak/Clearwater Small Hydropower	3	3
74		Elwha Hydro	0	0
75		Glines Canyon Hydro	0	0
76		Rocky Brook	0.25	0.25
77	Augmentation Purchases		0	0
78	Tier 2 Purchases		70	82
79	Federal Trans. Losses		(238)	(237)
80	Total Net Resources		**7,861**	**7,767**
81				
82	Total Firm Surplus/Deficit		**57**	**(78)**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	D	E
4			**2016**	**2017**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	1,839	1,899
10		Load Following	3,292	3,297
11		Slice (output energy)	1,917	1,889
12		Tier 2	70	82
14		5(c) Exchange	5,483	5,505
15	Industrial Firm - 7(c) Loads			
16		Direct Service Industries	94	94
17	New Resources - 7(f) Loads			
18		NR	0.001	0.001
19	Surplus Firm - SP Loads			
20		Avista & Puget (WNP#3 Settle.)	92	92
21		Dittmer/Substation Sale	10	10
22	Total Loads		**12,797**	**12,867**
23				
24	**Resources**			
25	Federal Base System			
26		Hydro	6,760	6,838
27		Other Resources		
28		Small Thermal & Misc.		
29		Combustion Turbines		
30		Renewables	0	0
31		Cogeneration		
32		Imports	15	1
33		Regional Transfers (In)	30	30
34		Large Thermal	1,075	916
35		Non-Utility Generation	0	0
36		Slice Loss Return	35	35
37		Augmentation Purchases	0	81
38		Tier 2 Purchases	70	82

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	D	E
4			**2016**	**2017**
39	less: FBS Obligations			
40		BC Hydro (Cdn Entitlement)	(486)	(482)
41		Non-Treaty Storage	(12)	(12)
42		Libby Coordination	0	0
43		Hungry Horse	(7)	(5)
44		Upper Baker	(1)	(1)
45		USBR Pump Load	(189)	(190)
46	less: FBS Uses			
47		Pasadena	0	0
48		Riverside	(2)	0
49		PacifiCorp	(4)	(4)
50		PG&E	(27)	(27)
51		Intertie Losses	(1)	(1)
52	Exchange Resources			
53		5(c) Exchange	5,483	5,505
54	New Resources			
55		Cowlitz Falls	26	27
56		Idaho Falls	14	14
57		Foote Creek 1	4	4
58		Foote Creek 2	0	0
59		Foote Creek 4	4	4
60		Stateline Wind Project	21	21
61		Condon Wind Project	10	10
62		Klondike I	7	7
63		Klondike III	14	14
64		Georgia-Pacific Paper (Wauna)	11	0
65		Fourmile Hill Geothermal	0	0
66		Ashland Solar Project	0	0
67		White Bluffs Solar	0	0
68		Dworshak/Clearwater Small Hydropower	3	3
69		Elwha Hydro	0	0
70		Glines Canyon Hydro	0	0
71		Rocky Brook	0	0
72	Total Resources		**12,853**	**12,867**

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
5			
6	**Loads (after adjustments)**		
7	Public	7,118	7,167
8	Exchange	5,483	5,505
9	DSI	94	94
10	NR	0.001	0.001
11	FPS	158	102
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,601	12,671
15	Industrial Firm - 7(c) Loads	94	94
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	158	102
18	Total Firm Loads	12,853	12,867
19	Secondary	2,293	2,191
20	Surplus Firm - SP Loads (for rate protection)	158	102
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,256	7,259
24	Exchange Resources	5,483	5,505
25	New Resources	114	103
26	Total Firm Resources	12,853	12,867
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,256	7,259
31	Industrial Firm - 7(c) Loads	0	0
32	New Resources - 7(f) Loads	0	0
33	Surplus Firm - SP Loads	0	0
34	Exchange Resources		
35	Priority Firm - 7(b) Loads	5,345	5,412
36	Industrial Firm - 7(c) Loads	51	44
37	New Resources - 7(f) Loads	0.0006	0.0005
38	Surplus Firm - SP Loads	87	48
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	42	49
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	72	54

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9845	0.9860
48	Industrial Firm - 7(c) Loads	0.0058	0.0067
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0097	0.0073
51	Federal Base System		
52	Priority Firm - 7(b) Loads	1.0000	1.0000
53	Industrial Firm - 7(c) Loads	0.0000	0.0000
54	New Resources - 7(f) Loads	0.0000	0.0000
55	Surplus Firm - SP Loads	0.0000	0.0000
56	Exchange Resources		
57	Priority Firm - 7(b) Loads	0.9748	0.9831
58	Industrial Firm - 7(c) Loads	0.0094	0.0081
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0158	0.0088
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.3726	0.4791
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.6274	0.5209
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9804	0.9848
68	Industrial Firm - 7(c) Loads	0.0073	0.0073
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0123	0.0079
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9926	0.9926
83	Industrial Firm - 7(c) Loads	0.0074	0.0074
84	New Resources - 7(f) Loads	0.0000	0.0000
85	Surplus Firm - SP Loads	-1.0000	-1.0000
89	Rate Protection		
90	PF Exchange	0.6830	0.6975
91	Industrial Firm - 7(c) Loads	0.0117	0.0119
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3053	0.2906

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	262,948	322,473
8	Bureau of Reclamation	156,818	158,121
9	Corps of Engineers	243,885	250,981
10	Billing Credits Generation	5,300	5,300
11	Cowlitz Falls O&M	4,300	4,548
12	Idaho Falls Bulb Turbine	5,015	5,095
13	Bureau O&M - Elwha	-	-
14	Clearwater Hatchery Generation	1,100	1,115
15	New Resources Integration Wheeling	975	975
16	Wauna	5,612	-
17	Other New Resources	-	-
18			
19	**Operating Generation Settlement Payment**		
20	Operating Generation Settlement Payment (Colville)	19,323	19,651
21			
22	**Non-Operating Generation**		
23	Trojan Decomissioning	800	800
24	WNP-1&3 Decomissioning	800	1,063
25			
26	**Contracted and Augmentation Power Purchases**		
27	Augmentation Power Purchases	-	20,960
28	Balancing Purchases	14,406	13,598
29	PNCA Headwater Benefits	3,000	3,000
30	Tier 1 Augmentation Resources (Klondike III)	10,048	10,158
31	Hedging/Mitigation	8,711	38,438
32	Other Committed Purchase (excl. Hedging)	225	225
33	Bookout Adj to Contracted Power Purchases	-	-
34			
35	**Exchanges and Settlements**		
36	Residential Exchange (IOU)	214,100	214,100
37	Residential Exchange (COU)	4,876	4,903
38	Residential Exchange (Refund)	76,538	76,538
39	Residential Exchange Program Support	920	635
40	Residential Exchange Interest Accrual	-	-
41			
42	**Renewable and Conservation Generation**		
43	Renewables R&D	1,819	1,823
44	Renewable Generation	30,939	31,483
45	Green Energy Premium (contra-expense)	-	-
46	Generation Conservation R&D	4,214	4,223
47	DR & Smart Grid	1,245	1,245
48	Conservation Acquisition	101,932	104,702
49	Low Income Energy Efficiency	5,336	5,422
50	Reimbursable Energy Efficiency Development	15,000	7,000
51	Legacy Conservation	605	605
52	Market Transformation	12,531	12,691

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
53			
54	**Transmission Acquisition and Ancillary Services**		
55	Trans & Ancillary Svcs	73,093	69,735
56	Trans & Ancillary Svcs (sys oblig)	35,815	35,073
57	Third Party GTA Wheeling	63,567	76,521
58	Power 3rd Party Trans & Ancillary Svcs	2,381	2,428
59	Trans Acq Generation Integration	12,142	12,074
60	Power Telemetering/Equipment Replacement	-	-
61			
62	**Power Non-Generation Operations**		
63	Efficiencies Program	-	-
64	Systems Operations R&D	-	-
65	Information Technology	5,805	5,910
66	Generation Project Coordination	7,735	7,845
67	Slice costs Charged to Slice Customers	-	-
68	Slice Implementation	1,101	1,131
69			
70	**PS Scheduling**		
71	Operations Scheduling	10,307	10,496
72	Scheduling R&D	-	-
73	Operations Planning	7,100	7,255
74			
75	**PS Marketing and Business Support**		
76	Sales and Support	22,139	24,854
77	Strategy, Finance & Risk Mgmt	21,628	21,541
78	Executive and Administrative Svcs	4,317	4,392
79	Conservation Support	9,456	9,731
80			
81	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
82	Fish and Wildlife	267,000	274,000
83	USF&W Lower Snake Hatcheries	32,303	32,949
84	Planning Council	11,236	11,446
85	Environmental Requirements	-	-
86			
87	**BPA Internal Support**		
88	Additional Post-Retirement Contribution	19,143	19,478
89	Agency Svs for Power for Rev Req schedule	42,731	44,345
90	Agency Svs for Energy Efficiency for Rev Req schedule	10,406	10,823

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
91			
92	**Bad Debt Expense/Other**		
93	Bad Debt Expense (composite)	-	-
94	Bad Debt Expense (non-slice)	-	-
95	Other Income, Expenses, Adjustments (composite)	(25,896)	(61,926)
96	Other Income, Expenses, Adjustments (non-slice)	-	-
97	Expense Offset (composite)	(71,542)	(67,685)
98			
99	**Non-Federal Debt Service**		
100	**Energy Northwest Debt Service**		
101	CGS Debt Service	100,810	127,466
102	WNP-1 Debt Service	258,325	201,804
103	WNP-3 Debt Service	225,942	256,332
104	EN Retired Debt	-	-
105			
106	**Non-Energy Northwest Debt Service**		
107	Conservation (CARES) Debt Service	-	-
108	Cowlitz Falls (Lewis County) Debt Service	7,300	7,303
109	Northern Wasco Debt Service	1,931	1,935
110			
111	**Depreciation and Amortization**		
112	**Depreciation**		
113	Depreciation - BPA	20,670	20,048
114	Depreciation - Corps	93,505	96,451
115	Depreciation - Bureau	26,026	26,969
116			
117	**Amortization**		
118	Amortization - Legacy Conservation	-	-
119	Amortization - Conservation Acquisitions	39,795	39,795
120	Amortization - CRFM	9,414	9,414
121	Amortization - Fish & Widlife	33,141	35,825
122			
123	**Interest Expense**		
124	**Net Interest**		
125	Interest On Appropriated Funds	189,757	186,051
126	Capitalization Adjustment	(45,937)	(45,937)
127	Interest On Treasury Bonds	56,935	69,299
128	Non Federal Interest (Prepay)	13,273	12,469
129	Capitalized Bond Premium	-	-
130	AFUDC	(10,731)	(11,360)
131	Interest Earned on BPA Fund for Power (composite)	(8,440)	(15,226)
132	Prepay Offset Credit	(468)	-
133	Interest Earned on BPA Fund for Power (non-slice)	(2,634)	(3,094)

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
134			
135	**Net Interest into Cost Pools**		
136	Power Net Interest - Hydro Allocation	159,008	159,561
137	Power Net Interest - Fish & Wildlife Allocation	14,239	15,559
138	Power Net Interest - Conservation Allocation	16,583	15,623
139	Power Net Interest - BPA Programs Allocation	1,925	1,459
140			
141	**Net Interest into Cost Pools 7b2**		
142	Power Net Interest Hydro 7b2 Allocation	159,008	159,561
143	Power Net Interest Fish & Wildlife 7b2 Allocation	14,239	15,559
144	Power Net Interest BPA Programs 7b2 Allocation	18,508	17,082
145			
146	**Net Revenue**		
147	**Minimum Required Net Revenue**		
148	Repayment of Treasury Borrowings	10,500	35,150
149	Payment of Irrigation Assistance	61,066	51,482
150	Depreciation (MRNR - Reverse sign)	(140,201)	(143,468)
151	Amortization (MRNR - Reverse sign)	(82,350)	(85,034)
152	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
153	Capitalized Bond Premium (Reverse Sign)	-	-
154	Repayment of Federal Appropriations	84,197	74,279
155	PGE WNP #3 Settlement	3,524	3,524
156	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
157	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
158	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(13,273)	(12,469)
159	Conservation Billing Credits (MRNR Adjustment - Reverse Sign)	-	-
160	Revenue Financing Requirement	-	-
161	Depreciation Exceeds Cash Expense	0	(0)
162			
163	**Minimum Net Revenue into Cost Pools**		
164	Power MNetRev - Hydro Allocation	-	0
165	Power MNetRev - Fish & Wildlife Allocation	-	-
166	Power MNetRev - Conservation Allocation	-	-
167	Power MNetRev - BPA Programs Allocation	-	-
168			
169	**Minimum Net Revenue into Cost Pools 7b2**		
170	Power MNetRev - Hydro 7b2 Allocation	-	0
171	Power MNetRev - Fish & Wildlife 7b2 Allocation	-	-
172	Power MNetRev - PBA Programs 7b2 Allocation	-	-
173			
174	**Planned Net Revenues for Risk into Cost Pools**		
175	Power PNetRev - Hydro Allocation	-	-
176	Power PNetRev - Fish & Wildlife Allocation	-	-
177	Power PNetRev - Conservation Allocation	-	-
178	Power PNetRev - BPA Programs Allocation	-	-
179			
180	**Planned Net Revenues for Risk into Cost Pools 7b2**		
181	Power PNetRev - Hydro 7b2 Allocation	-	-
182	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-
183	Power PNetRev - BPA Programs 7b2 Allocation	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
184			
185	**Internally Computed Line Items**		
186	Augmentation Power Purchases	-	20,960
187	Balancing Purchases	23,117	52,036
188	Secondary Energy Credit	(339,686)	(358,701)
189	Low Density Discount Costs	39,865	40,464
190	Irrigation Rate Mitigation Costs	22,146	22,146
191	**Charges/Credits to Tiered Rate Pools**		
192	Firm Surplus and Secondary Credit (from unused RHWM)	(5,991)	(2,744)
193	Balancing Augmentation	(1,445)	(10,543)
194	Transmission Loss Adjustment	(29,120)	(29,437)
195	Demand Revenue	47,946	48,763
196	Load Shaping Revenue	4,040	11,564
197	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
198	Augmentation RSS & RSC Adder	2,445	2,445
199	Tier 2 Purchase Costs	22,058	26,582
200	Tier 2 Rate Design Adjustments (Cost)	808	926
201	Tier 2 Other Costs	-	-
202			
203	**Revenue Credits / Rate Design Adjustments**		
204	Downstream Benefits and Pumping Power	(17,219)	(17,219)
205	Generation Inputs for Ancillary and Other Services Revenue	(115,750)	(115,750)
206	4(h)(10)(c)	(91,107)	(87,786)
207	Colville and Spokane Settlements	(4,600)	(4,600)
208	Green Tags (FBS resources)	-	-
209	Green Tags (New resources)	(1,151)	(648)
210	Energy Efficiency Revenues	(15,000)	(7,000)
211	Large Project Revenues	-	-
212	Miscellaneous Credits (incl. GTA)	(5,750)	(5,800)
213	Pre-sub/Hungry Horse	(2,036)	(1,506)
214	Other Locational/Seasonal Exchange	(565)	(565)
215	Upper Baker	(457)	(466)
216	WNP3 Settlement	(34,537)	(34,537)
217	Other Long-Term Contracts	(3,408)	(3,408)
218	Network Wind Integration & Shaping	-	-
219	Slice Billing Adjustment	(3,877)	-
220	Trading Floor pre-sale of Secondary	(10,666)	(12,584)
221	NR Revenues from ESS energy and capacity charges	(356)	(356)
222	**Tier 2**		
223	Composite Augmentation RSS Revenue Debit/(Credit)	(1,725)	(1,725)
224	Composite Tier 2 RSS Revenue Debit/(Credit)	(83)	(91)
225	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(725)	(835)
226	Composite Non-Federal RSS Revenue Debit/(Credit)	(1,241)	(1,652)
227	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(720)	(720)
228	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
229	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
230	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	69	(26)

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2015 - September 2017
($ 000)

	B	D	E
3		**2016**	**2017**
4			
5	**Federal Base System**	**1,964,731**	**2,104,595**
6	Hydro	743,282	757,097
7	Operating Expense	584,274	597,536
8	Net Interest	159,008	159,561
9	PNRR	-	-
10	MRNR	-	0
11	BPA Fish and Wildlife Program	325,616	336,830
12	Operating Expense	311,377	321,271
13	Net Interest	14,239	15,559
14	PNRR	-	-
15	MRNR	-	-
16	Trojan	800	800
17	WNP #1	259,125	202,867
18	WNP #2	363,758	449,939
19	WNP #3	225,942	256,332
20	System Augmentation	-	20,960
21	Balancing	23,342	52,261
22	Tier 2 Costs	22,866	27,508
23			
24	**New Resources**	**69,040**	**64,435**
25	Idaho Falls	5,015	5,095
26	Tier 1 Aug (Klondike III)	10,048	10,158
27	Cowlitz Falls	11,600	11,851
28	Other NR	42,377	37,331
29			
30	**Residential Exchange**	**3,040,879**	**3,044,239**
31			
32	**Conservation**	**222,404**	**217,160**
33	Operating Expense	205,821	201,537
34	Net Interest	16,583	15,623
35	PNRR	-	-
36	MRNR	-	-
37			
38	**BPA Programs**	**67,164**	**39,144**
39	Operating Expense	65,239	37,685
40	Net Interest	1,925	1,459
41	PNRR	-	-
42	MRNR	-	-
43			
44			
45	**Transmission**	**186,998**	**195,832**
46	TBL Transmission/Ancillary Services	121,050	116,882
47	3Rd Party Trans/Ancillary Services	2,381	2,428
48	General Transfer Agreements	63,567	76,521
49			
50	**Total PBL Revenue Requirement**	**5,551,217**	**5,665,404**
51			
52	**Transmission Revenue Requirement**	**811,131**	**863,467**
53	Operating Expense	602,570	644,203
54	Net Interest	130,625	145,757
55	PNRR	-	-
56	MRNR	77,936	73,507

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 000)

	B		D		E	F	G	H
18	Program Totals		2016		2017			
19	Low Density Discount Expenses........................	$	39,865	$	40,464			
20	Irrigation Rate Discount....................................	$	22,146	$	22,146			
21								
22								
23	TRM Costs after Adjustments		2016		2017			
24	Composite..	$	2,427,590	$	2,440,841			
25	Non-Slice...	$	(262,935)	$	(264,905)			
26	Slice...	$	-	$	-			
27	Tier 2..	$	22,866	$	27,508			
28	Total Costs	$	2,187,521	$	2,203,445			
29								
30	Low Density Discount							
31	Customer Charge LDD		2016		2017			
32	TOCA LDD Offest %..		1.67%		1.69%			
33	LDD Customer Charge ($000).........................	$	36,215	$	36,723			
34								
35	Irrigation Rate Discount							
36	IRD Percentage..		37.06%					
37	Total Irrigation Load (MWh)..........................		1,881,605					
38	RT1SC..		6,983					
39	Irrigation Load Weighted LDD.......................		4.90%					
40								
41			2016		2017			
42	Hours..		8784		8760			
43	IRD TOCA..		3.06753%		3.07593%			
44	Composite Revenue...	$	75,931,191	$	76,139,117			
45	Non-Slice Revenue...	$	(11,287,967)	$	(11,318,878)			
46	Load Shaping Revenue......................................	$	(1,915,344)	$	(1,902,655)			
47	Total after LDD..	$	59,654,214	$	59,834,623			
48								
49	Irrigation Rate Discount....................................		11.77					
50								
51								

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 000)

	B	D	E	F	G	H
52	Demand and Load Shaping Discount	Demand BD (kW)	LoadShp BD (MWh)	Demand Rate	LoadShp Rate	Total LDD Discount
53	Oct-15	16,127	(3,340)	$ 10.02	$ 27.86	$ 68,554
54	Oct-15	-	938	$ 10.02	$ 23.75	$ 22,268
55	Nov-15	9,847	(8,634)	$ 10.27	$ 28.56	$ (145,441)
56	Nov-15	-	515	$ 10.27	$ 24.48	$ 12,594
57	Dec-15	29,019	4,027	$ 10.51	$ 29.22	$ 422,664
58	Dec-15	-	7,977	$ 10.51	$ 24.82	$ 198,018
59	Jan-16	21,265	9,597	$ 10.79	$ 30.02	$ 517,536
60	Jan-16	-	11,976	$ 10.79	$ 25.03	$ 299,753
61	Feb-16	15,683	7,595	$ 10.66	$ 29.65	$ 392,401
62	Feb-16	-	8,227	$ 10.66	$ 24.68	$ 203,052
63	Mar-16	21,343	(1,869)	$ 9.13	$ 25.38	$ 147,422
64	Mar-16	-	1,165	$ 9.13	$ 22.07	$ 25,717
65	Apr-16	19,498	4,342	$ 8.76	$ 24.36	$ 276,566
66	Apr-16	-	4,636	$ 8.76	$ 21.04	$ 97,524
67	May-16	11,102	(22,493)	$ 7.95	$ 22.10	$ (408,830)
68	May-16	-	(4,912)	$ 7.95	$ 17.53	$ (86,110)
69	Jun-16	18,851	(4,573)	$ 8.33	$ 23.15	$ 51,142
70	Jun-16	-	1,133	$ 8.33	$ 17.11	$ 19,383
71	Jul-16	15,413	5,571	$ 9.87	$ 27.43	$ 304,923
72	Jul-16	-	12,421	$ 9.87	$ 21.58	$ 268,011
73	Aug-16	21,863	2,346	$ 10.90	$ 30.30	$ 309,382
74	Aug-16	-	8,382	$ 10.90	$ 24.41	$ 204,615
75	Sep-16	15,038	4,222	$ 11.42	$ 31.75	$ 305,786
76	Sep-16	-	5,594	$ 11.42	$ 25.70	$ 143,762
77	**Total**					**$ 3,650,691**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 000)

	B	D	E	F	G	H
78	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**	**LoadShp Rate**	**Total LDD Discount**
79	Oct-16	13,480	(3,488)	$ 10.02	$ 27.86	$ 37,901
80	Oct-16	-	1,362	$ 10.02	$ 23.75	$ 32,354
81	Nov-16	13,889	(8,078)	$ 10.27	$ 28.56	$ (88,080)
82	Nov-16	-	275	$ 10.27	$ 24.48	$ 6,728
83	Dec-16	29,515	4,038	$ 10.51	$ 29.22	$ 428,212
84	Dec-16	-	8,018	$ 10.51	$ 24.82	$ 199,029
85	Jan-17	22,125	9,540	$ 10.79	$ 30.02	$ 525,096
86	Jan-17	-	12,226	$ 10.79	$ 25.03	$ 306,020
87	Feb-17	12,708	9,124	$ 10.66	$ 29.65	$ 406,029
88	Feb-17	-	9,016	$ 10.66	$ 24.68	$ 222,510
89	Mar-17	21,495	(1,768)	$ 9.13	$ 25.38	$ 151,372
90	Mar-17	-	1,035	$ 9.13	$ 22.07	$ 22,851
91	Apr-17	16,048	4,032	$ 8.76	$ 24.36	$ 238,786
92	Apr-17	-	4,966	$ 8.76	$ 21.04	$ 104,460
93	May-17	14,702	(22,596)	$ 7.95	$ 22.10	$ (382,480)
94	May-17	-	(5,411)	$ 7.95	$ 17.53	$ (94,840)
95	Jun-17	19,216	(4,634)	$ 8.33	$ 23.15	$ 52,764
96	Jun-17	-	1,102	$ 8.33	$ 17.11	$ 18,853
97	Jul-17	15,987	5,533	$ 9.87	$ 27.43	$ 309,537
98	Jul-17	-	12,601	$ 9.87	$ 21.58	$ 271,910
99	Aug-17	21,948	2,479	$ 10.90	$ 30.30	$ 314,348
100	Aug-17	-	8,313	$ 10.90	$ 24.41	$ 202,927
101	Sep-17	15,249	4,271	$ 11.42	$ 31.75	$ 309,747
102	Sep-17	-	5,630	$ 11.42	$ 25.70	$ 144,671
103	**Total**					**$ 3,740,707**

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Costs ($000)**	**2016**	**2017**
5	**FBS...**	$ 1,964,731	$ 2,104,595
6	**New Resources.....................................**	$ 69,040	$ 64,435
7	**Residential Exchange..........................**	$ 3,040,879	$ 3,044,239
8	**Conservation..**	$ 222,404	$ 217,160
9	**BPAPrograms......................................**	$ 67,164	$ 39,144
10	**Transmission..**	$ 186,998	$ 195,832
11	**Irrigation/Low Density Discounts.......**	$ 62,012	$ 62,610
12	Total..	$ 5,613,228	$ 5,728,015
13			
14	**Cost Allocation**		
15			
16	**FBS...**	$ 1,964,731	$ 2,104,595
17			
18	**Federal Base System Allocators...........**	**2016**	**2017**
19	Priority Firm - 7(b) Loads.....................	1.0000	1.0000
20	Industrial Firm - 7(c) Loads..................	0.0000	0.0000
21	New Resources - 7(f) Loads..................	0.0000	0.0000
22	Surplus Firm - SP Loads.......................	0.0000	0.0000
23	Total..	1.0000	1.0000
24			
25	**FBS Cost Allocation............................**	**2016**	**2017**
26	Priority Firm - 7(b) Loads.....................	$ 1,964,731	$ 2,104,595
27	Industrial Firm - 7(c) Loads..................	$ -	$ -
28	New Resources - 7(f) Loads..................	$ -	$ -
29	Surplus Firm - SP Loads.......................	$ -	$ -
30	Total..	$ 1,964,731	$ 2,104,595
31			
32			
33	**Irrigation/Low Density Discounts.......**	$ 62,012	$ 62,610
34			
35	**Irrigation/LDD Allocators..................**	**2016**	**2017**
36	Priority Firm - 7(b) Loads.....................	1.0000	1.0000
37	Industrial Firm - 7(c) Loads..................	0.0000	0.0000
38	New Resources - 7(f) Loads..................	0.0000	0.0000
39	Surplus Firm - SP Loads.......................	0.0000	0.0000
40	Total..	1.0000	1.0000
41			
42	**Irrigation/LDD Cost Allocation...........**	**2016**	**2017**
43	Priority Firm - 7(b) Loads.....................	$ 62,012	$ 62,610
44	Industrial Firm - 7(c) Loads..................	$ -	$ -
45	New Resources - 7(f) Loads..................	$ -	$ -
46	Surplus Firm - SP Loads.......................	$ -	$ -
47	Total..	$ 62,012	$ 62,610

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B	C		D	
4	**Costs ($000)**		**2016**		**2017**
5	**FBS..**	$	1,964,731	$	2,104,595
6	**New Resources......................................**	$	69,040	$	64,435
7	**Residential Exchange............................**	$	3,040,879	$	3,044,239
8	**Conservation...**	$	222,404	$	217,160
9	**BPAPrograms.......................................**	$	67,164	$	39,144
10	**Transmission...**	$	186,998	$	195,832
11	**Irrigation/Low Density Discounts.........**	$	62,012	$	62,610
12	Total...	$	5,613,228	$	5,728,015
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources......................................**	$	69,040	$	64,435
17					
18	**New Resources Allocators**		**2016**		**2017**
19	Priority Firm - 7(b) Loads......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads....................		0.3726		0.4791
21	New Resources - 7(f) Loads...................		0.00000409		0.00000526
22	Surplus Firm - SP Loads.........................		0.6274		0.5209
23	Total...		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2016**		**2017**
26	Priority Firm - 7(b) Loads......................	$	-	$	-
27	Industrial Firm - 7(c) Loads....................	$	25,721	$	30,873
28	New Resources - 7(f) Loads...................	$	0.2823	$	0.3388
29	Surplus Firm - SP Loads.........................	$	43,319	$	33,562
30	Total...	$	69,040	$	64,435
31					
32					
33	**Residential Exchange............................**	$	3,040,879	$	3,044,239
34	Costs Functionalized to Transmission.....	$	(214,978)	$	(215,225)
35	Costs Functionalized to Generation.........	$	2,825,901	$	2,829,014
36					
37	**Residential Exchange Allocators**		**2016**		**2017**
38	Priority Firm - 7(b) Loads......................		0.9748		0.9831
39	Industrial Firm - 7(c) Loads....................		0.0094		0.0081
40	New Resources - 7(f) Loads...................		0.00000010		0.00000009
41	Surplus Firm - SP Loads.........................		0.0158		0.0088
42	Total...		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2016**		**2017**
45	Priority Firm - 7(b) Loads......................	$	2,754,752	$	2,781,338
46	Industrial Firm - 7(c) Loads....................	$	26,507	$	22,842
47	New Resources - 7(f) Loads...................	$	0.291	$	0.251
48	Surplus Firm - SP Loads.........................	$	44,642	$	24,834
49	Total...	$	2,825,901	$	2,829,014

Table 2.3.4.3

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B		C		D
4	**Costs ($000)**		**2016**		**2017**
5	**FBS..**	$	1,964,731	$	2,104,595
6	**New Resources................................**	$	69,040	$	64,435
7	**Residential Exchange.......................**	$	3,040,879	$	3,044,239
8	**Conservation....................................**	$	222,404	$	217,160
9	**BPAPrograms..................................**	$	67,164	$	39,144
10	**Transmission...................................**	$	186,998	$	195,832
11	**Irrigation/Low Density Discounts...**	$	62,012	$	62,610
12	Total..	$	5,613,228	$	5,728,015
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	222,404	$	217,160
17					
18	**BPAPrograms..................................**	$	67,164	$	39,144
19					
20	**Transmission...................................**	$	186,998	$	195,832
21					
22					
23	**Conservation & General Allocators**		**2016**		**2017**
24	Priority Firm - 7(b) Loads.................		0.9804		0.9848
25	Industrial Firm - 7(c) Loads..............		0.0073		0.0073
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0123		0.0079
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2016**		**2017**
31	Priority Firm - 7(b) Loads.................	$	218,042	$	213,852
32	Industrial Firm - 7(c) Loads..............	$	1,625	$	1,585
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	2,737	$	1,723
35	Total..	$	222,404	$	217,160
36					
37	**BPA Programs Cost Allocation.......**		**2016**		**2017**
38	Priority Firm - 7(b) Loads.................	$	65,847	$	38,548
39	Industrial Firm - 7(c) Loads..............	$	491	$	286
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	826	$	311
42	Total..	$	67,164	$	39,144
43					
44	**Transmission Cost Allocation..........**		**2016**		**2017**
45	Priority Firm - 7(b) Loads.................	$	183,331	$	192,849
46	Industrial Firm - 7(c) Loads..............	$	1,366	$	1,429
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	2,301	$	1,554
49	Total..	$	186,998	$	195,832

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2015 - September 2017
($ 000)

	B	C		D	
4	**Costs ($000)**		**2016**		**2017**
5	**FBS...**	$	1,964,731	$	2,104,595
6	**New Resources.......................................**	$	69,040	$	64,435
7	**Residential Exchange............................**	$	3,040,879	$	3,044,239
8	**Conservation..**	$	222,404	$	217,160
9	**BPAPrograms..**	$	67,164	$	39,144
10	**Transmission..**	$	186,998	$	195,832
11	**Irrigation/Low Density Discounts........**	$	62,012	$	62,610
12	Total..	$	5,613,228	$	5,728,015
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2016**		**2017**
18	Priority Firm - 7(b) Loads.......................	$	5,248,715	$	5,393,791
19	Industrial Firm - 7(c) Loads...................	$	55,710	$	57,014
20	New Resources - 7(f) Loads...................	$	0.61	$	0.63
21	Surplus Firm - SP Loads.........................	$	93,824	$	61,984
22	Total Costs Functionalized to Power......	$	5,398,250	$	5,512,790
23					
24					
25					
26	REP Cost Functionalized to Transmissio	$	214,978	$	215,225
27					
28	Total COSA Revenue Requirement	$	5,613,228	$	5,728,015

Cost of Service Analysis
General Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C		D	
5	**General Revenue Credits ($000))**		**2016**		**2017**
6					
7	**FBS**	**$**	**(113,734)**	**$**	**(110,530)**
8	Hydro and Renewable	$	(21,819)	$	(21,819)
9	Downstream Benefits and Pumping Power	$	(17,219)	$	(17,219)
10	Colville and Spokane Settlements	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)	$	-	$	-
12	Fish and Wildlife	$	(91,107)	$	(87,786)
13	4(h)(10)(c)	$	(91,107)	$	(87,786)
14	Tier 2 Adjustment	$	(808)	$	(926)
15	**Contract Obligations**	**$**	**(3,058)**	**$**	**(2,537)**
16	Pre-sub/Hungry Horse	$	(2,036)	$	(1,506)
17	Other Locational/Seasonal Exchange	$	(565)	$	(565)
18	Upper Baker	$	(457)	$	(466)
19	**New Resources**	**$**	**(1,151)**	**$**	**(648)**
20	Green Tags (New resources)	$	(1,151)	$	(648)
21	**Conservation**	**$**	**(15,000)**	**$**	**(7,000)**
22	Energy Efficiency Revenues	$	(15,000)	$	(7,000)
23	Large Project Revenues	$	-	$	-
24	**BPAPrograms**	**$**	**-**	**$**	**-**
25	**Transmission**	**$**	**(5,750)**	**$**	**(5,800)**
26	Miscellaneous Credits (incl. GTA)	$	(5,750)	$	(5,800)
27					
28	**Other Revenue Credits ($ 000))**		**2016**		**2017**
29	Secondary Revenue	**$**	**(457,461)**	**$**	**(480,890)**
30	Incl. Slice	$	(457,461)	$	(480,890)
31	Generation Inputs for Ancillary and Other Services Revenue	**$**	**(115,750)**	**$**	**(115,750)**
32	Composite Non-Federal RSS Revenue Debit/(Credit)	**$**	**(1,241)**	**$**	**(1,652)**
33	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$**	**69**	**$**	**(26)**
34	NR Revenues from ESS energy and capacity charges	**$**	**(356)**	**$**	**(356)**
35	**Contract Revenue from Other Long-term Sales**	**$**	**(41,822)**	**$**	**(37,945)**
36	WNP3 Settlement	$	(34,537)	$	(34,537)
37	Slice Billing Adjustment	$	(3,877)	$	-
38	Other Long-Term Contracts	$	(3,408)	$	(3,408)
39					
40	**Total Revenue Credits**	$	(755,253)	$	(763,135)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2016**		**2017**
5	Priority Firm - 7(b) Loads..	$	5,248,715	$	5,393,791
6	Industrial Firm - 7(c) Loads....................................	$	55,710	$	57,014
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	93,824	$	61,984
9	Total...	$	5,398,250	$	5,512,790
10					
11	**General Revenue Credits ($000))**		**2016**		**2017**
12					
13	**FBS...**	**$**	**(116,792)**	**$**	**(113,068)**
14	Hydro and Renewable..	$	(21,819)	$	(21,819)
15	Downstream Benefits and Pumping Power..	$	(17,219)	$	(17,219)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife..	$	(91,107)	$	(87,786)
19	4(h)(10)(c)..	$	(91,107)	$	(87,786)
20	Tier 2 Adjustment...	$	(808)	$	(926)
21	Contract Obligations...	$	(3,058)	$	(2,537)
22	Pre-sub/Hungry Horse.................................	$	(2,036)	$	(1,506)
23	Other Locational/Seasonal Exchange...........	$	(565)	$	(565)
24	Upper Baker...	$	(457)	$	(466)
25					
26	**Federal Base System Allocators**		**2016**		**2017**
27	Priority Firm - 7(b) Loads..		1.0000		1.0000
28	Industrial Firm - 7(c) Loads....................................		0.0000		0.0000
29	New Resources - 7(f) Loads....................................		0.0000		0.0000
30	Surplus Firm - SP Loads...		0.0000		0.0000
31	Total...		1.0000		1.0000
32					
33	**FBS Credit Allocation**		**2016**		**2017**
34	Priority Firm - 7(b) Loads..	$	(116,792)	$	(113,068)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total...	$	(116,792)	$	(113,068)
39					
40	**Allocation of Revenue Requirement**		**2016**		**2017**
41	Priority Firm - 7(b) Loads..	$	5,131,923	$	5,280,723
42	Industrial Firm - 7(c) Loads....................................	$	55,710	$	57,014
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	93,824	$	61,984
45	Total...	$	5,281,458	$	5,399,722

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B		C		D
40	**Allocation of Revenue Requirement**		**2016**		**2017**
41	Priority Firm - 7(b) Loads.......................................	$	5,131,923	$	5,280,723
42	Industrial Firm - 7(c) Loads....................................	$	55,710	$	57,014
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	93,824	$	61,984
45	Total...	$	5,281,458	$	5,399,722
46					
47					
48	**General Revenue Credits (/$1000))**		**2016**		**2017**
49					
50	**Transmission...**	**$**	**(5,750)**	**$**	**(5,800)**
51	Miscellaneous Credits (incl. GTA)...................	$	(5,750)	$	(5,800)
52					
53	**Conservation & General Cost Allocators**		**2016**		**2017**
54	Priority Firm - 7(b) Loads.......................................		0.9804		0.9848
55	Industrial Firm - 7(c) Loads....................................		0.0073		0.0073
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0123		0.0079
58	Total...		1.0000		1.0000
59					
60	**Transmission Allocation**		**2016**		**2017**
61	Priority Firm - 7(b) Loads.......................................	$	(5,637)	$	(5,712)
62	Industrial Firm - 7(c) Loads....................................	$	(42)	$	(42)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(71)	$	(46)
65	Total...	$	(5,750)	$	(5,800)
66					
67	**Allocation of Revenue Requirement**		**2016**		**2017**
68	Priority Firm - 7(b) Loads.......................................	$	5,126,286	$	5,275,011
69	Industrial Firm - 7(c) Loads....................................	$	55,668	$	56,972
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	93,754	$	61,938
72	Total...	$	5,275,708	$	5,393,922

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2016**		**2017**
5	Priority Firm - 7(b) Loads................................	$	5,126,286	$	5,275,011
6	Industrial Firm - 7(c) Loads.............................	$	55,668	$	56,972
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads..................................	$	93,754	$	61,938
9	Total...	$	5,275,708	$	5,393,922
10					
11					
12	**General Revenue Credits ($000))**		**2016**		**2017**
13					
14	**New Resources..**	**$**	**(1,151)**	**$**	**(648)**
15	Green Tags (New resources)......................	$	(1,151)	$	(648)
16					
17					
18	**New Resources Cost Allocators**		**2016**		**2017**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.3726		0.4791
21	New Resources - 7(f) Loads............................		0.000004		0.000005
22	Surplus Firm - SP Loads..................................		0.6274		0.5209
23	Total...		1.0000		1.0000
24					
25	**New Resources Allocation**		**2016**		**2017**
26	Priority Firm - 7(b) Loads................................	$	-	$	-
27	Industrial Firm - 7(c) Loads.............................	$	(429)	$	(311)
28	New Resources - 7(f) Loads............................	$	(0.005)	$	(0.003)
29	Surplus Firm - SP Loads..................................	$	(722)	$	(338)
30	Total...	$	(1,151)	$	(648)
31					
32	**Allocation of Revenue Requirement**		**2016**		**2017**
33	Priority Firm - 7(b) Loads................................	$	5,126,286	$	5,275,011
34	Industrial Firm - 7(c) Loads.............................	$	55,239	$	56,662
35	New Resources - 7(f) Loads............................	$	0.606	$	0.622
36	Surplus Firm - SP Loads..................................	$	93,032	$	61,600
37	Total...	$	5,274,558	$	5,393,274
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B		C		D
32	**Allocation of Revenue Requirement**		**2016**		**2017**
33	Priority Firm - 7(b) Loads................................	$	5,126,286	$	5,275,011
34	Industrial Firm - 7(c) Loads.............................	$	55,239	$	56,662
35	New Resources - 7(f) Loads............................	$	0.606	$	0.622
36	Surplus Firm - SP Loads.................................	$	93,032	$	61,600
37	Total..	$	5,274,558	$	5,393,274
39					
40	**General Revenue Credits (/$1000))**		**2016**		**2017**
41					
42	**Conservation...**	**$**	**(15,000)**	**$**	**(7,000)**
43	Energy Efficiency Revenues......................	$	(15,000)	$	(7,000)
44	Large Project Revenues.............................	$	-	$	-
45					
46	**Conservation & General Cost Allocators**		**2016**		**2017**
47	Priority Firm - 7(b) Loads................................		0.9804		0.9848
48	Industrial Firm - 7(c) Loads.............................		0.0073		0.0073
49	New Resources - 7(f) Loads............................		0.0000001		0.0000001
50	Surplus Firm - SP Loads.................................		0.0123		0.0079
51	Total..		1.0000		1.0000
52					
53	**Conservation Allocation**		**2016**		**2017**
54	Priority Firm - 7(b) Loads................................	$	(14,706)	$	(6,893)
55	Industrial Firm - 7(c) Loads.............................	$	(110)	$	(51)
56	New Resources - 7(f) Loads............................	$	(0.001)	$	(0.001)
57	Surplus Firm - SP Loads.................................	$	(185)	$	(56)
58	Total..	$	(15,000)	$	(7,000)
59					
60	**Allocation of Revenue Requirement**		**2016**		**2017**
61	Priority Firm - 7(b) Loads................................	$	5,111,580	$	5,268,118
62	Industrial Firm - 7(c) Loads.............................	$	55,130	$	56,610
63	New Resources - 7(f) Loads............................	$	0.605	$	0.621
64	Surplus Firm - SP Loads.................................	$	92,847	$	61,545
65	Total..	$	5,259,558	$	5,386,274

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2016**		**2017**
5	Priority Firm - 7(b) Loads..	$	5,111,580	$	5,268,118
6	Industrial Firm - 7(c) Loads..	$	55,130	$	56,610
7	New Resources - 7(f) Loads..	$	0.6050	$	0.6213
8	Surplus Firm - SP Loads..	$	92,847	$	61,545
9	Total..	$	5,259,558	$	5,386,274
10					
11	**General Revenue Credits (/$1000))**		**2016**		**2017**
12					
13	**Generation Inputs..**	**$**	**(115,750)**	**$**	**(115,750)**
14					
15	**NR Revenues from ESS energy and capacity charges.........**	**$**	**(356)**	**$**	**(356)**
16					
17	**Credit Due to Idaho Deemer Account...................................**	**$**	**-**	**$**	**-**
19					
20	**Conservation & General Cost Allocators**		**2016**		**2017**
21	Priority Firm - 7(b) Loads..		0.9804		0.9848
22	Industrial Firm - 7(c) Loads..		0.0073		0.0073
23	New Resources - 7(f) Loads..		0.0000001		0.0000001
24	Surplus Firm - SP Loads..		0.0123		0.0079
25	Total..		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2016**		**2017**
28	Priority Firm - 7(b) Loads..	$	(113,829)	$	(114,337)
29	Industrial Firm - 7(c) Loads..	$	(848)	$	(847)
30	New Resources - 7(f) Loads..	$	(0)	$	(0)
31	Surplus Firm - SP Loads..	$	(1,429)	$	(921)
32	Total..	$	(116,106)	$	(116,106)
33					
34	**Allocation of Revenue Requirement**		**2016**		**2017**
35	Priority Firm - 7(b) Loads..	$	4,997,751	$	5,153,781
36	Industrial Firm - 7(c) Loads..	$	54,282	$	55,763
37	New Resources - 7(f) Loads..	$	0.5957	$	0.6120
38	Surplus Firm - SP Loads..	$	91,419	$	60,624
39	Total..	$	5,143,452	$	5,270,168
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B		C		D
34	**Allocation of Revenue Requirement**		**2016**		**2017**
35	Priority Firm - 7(b) Loads..	$	4,997,751	$	5,153,781
36	Industrial Firm - 7(c) Loads..	$	54,282	$	55,763
37	New Resources - 7(f) Loads...	$	0.5957	$	0.6120
38	Surplus Firm - SP Loads...	$	91,419	$	60,624
39	Total..	$	5,143,452	$	5,270,168
41					
42	**Other Revenue Credits**		**2016**		**2017**
43	Composite Non-Federal RSS Revenue Debit/(Credit)........	$	(1,241)	$	(1,652)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit).........	$	69	$	(26)
45					
46					
47	**Conservation & General Cost Allocators**		**2016**		**2017**
48	Priority Firm - 7(b) Loads...		0.9804		0.9848
49	Industrial Firm - 7(c) Loads..		0.0073		0.0073
50	New Resources - 7(f) Loads...		0.0000001		0.0000001
51	Surplus Firm - SP Loads...		0.0123		0.0079
52	Total..		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2016**		**2017**
55	Priority Firm - 7(b) Loads...	$	(1,149)	$	(1,653)
56	Industrial Firm - 7(c) Loads..	$	(9)	$	(12)
57	New Resources - 7(f) Loads...	$	(0.0001)	$	(0.0001)
58	Surplus Firm - SP Loads...	$	(14)	$	(13)
59	Total..	$	(1,172)	$	(1,679)
60					
61	**Allocation of Revenue Requirement**		**2016**		**2017**
62	Priority Firm - 7(b) Loads...	$	4,996,602	$	5,152,128
63	Industrial Firm - 7(c) Loads..	$	54,273	$	55,751
64	New Resources - 7(f) Loads...	$	0.5956	$	0.6118
65	Surplus Firm - SP Loads...	$	91,404	$	60,610
66	Total..	$	5,142,280	$	5,268,490

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2015 - September 2017
(aMW, $ 000)

	C		D		E
4	**General Revenue Credits ($000))**		**2016**		**2017**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1759		1703
11					
12	Slice Percentage		26.6187%		26.6187%
13					
14	BPA Secondary Sales Pre-Slice, aMW (row 1 * (1-row 3))		2293		2191
15					
16	aMW to GWh Multiplier		8.784		8.760
17					
18	BPA Secondary Sales Pre-Slice GWh (row 5 * row 7)		20143		19196
19					
20	Secondary Sales Price	$	21.29	$	23.20
21	Adhoc Addition to Secondary (includes other commited sales)		10,666		12,584
22	BPA Secondary Sales Pre-Slice $000 (includes other commited sales)	$	457,461	$	480,890
23					
24	BPA Secondary Sales Allocated to 7b3 Rate Protection				
25					
26	**BPA Secondary Sales Available as Revenue Credit (row 13 - row 15)**	**$**	**457,461**	**$**	**480,890**
27					
28	Slice Portion of Secondary	$	117,775	$	122,188
29	Adhoc Addition to Secondary (California Adjustment)	$	3,627	$	3,627
30					
31	**Federal Base System + NR Cost Allocators**		**2016**		**2017**
32	Priority Firm - 7(b) Loads..		0.9845		0.9860
33	Industrial Firm - 7(c) Loads...		0.0058		0.0067
34	New Resources - 7(f) Loads..		0.0000		0.0000
35	Surplus Firm - SP Loads..		0.0097		0.0073
36	Total..		1.0000		1.0000
37					
38					
39	**Allocation of Secondary Revenues Credit**		**2016**		**2017**
40	Priority Firm - 7(b) Loads..	$	(450,384)	$	(474,147)
41	Industrial Firm - 7(c) Loads...	$	(2,637)	$	(3,231)
42	New Resources - 7(f) Loads..	$	(0.0289)	$	(0.0355)
43	Surplus Firm - SP Loads..	$	(4,440)	$	(3,512)
44	Total..	$	(457,461)	$	(480,890)
45					
46	**Allocation of Revenue Requirement**		**2016**		**2017**
47	Priority Firm - 7(b) Loads..	$	4,546,218	$	4,677,981
48	Industrial Firm - 7(c) Loads...	$	51,636	$	52,520
49	New Resources - 7(f) Loads..	$	0.5667	$	0.5764
50	Surplus Firm - SP Loads..	$	86,964	$	57,098
51	Total..	$	4,684,819	$	4,787,600

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2015 - September 2017
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2016		2017
6	Priority Firm - 7(b) Loads..	$	4,546,218	$	4,677,981
7	Industrial Firm - 7(c) Loads..	$	51,636	$	52,520
8	New Resources - 7(f) Loads...	$	0.5667	$	0.5764
9	Surplus Firm - SP Loads...	$	86,964	$	57,098
10	Total...	$	4,684,819	$	4,787,600
11					
12	**Contract Revenue from Other Long-term Sales............**	**$**	**(41,822)**	**$**	**(37,945)**
13	WNP3 Settlement..	$	(34,537)	$	(34,537)
14	Slice Billing Adjustment..	$	(3,877)	$	-
15	Other Long-Term Contracts....................................	$	(3,408)	$	(3,408)
16					
17	**Calculation of FPS Revenue Deficiency**		2016		2017
18	Surplus Firm - SP Loads...	$	86,964	$	57,098
19					
20	**Deficiency...**	**$**	**45,142**	**$**	**19,153**
21					
22					
23					
24	**Surplus Deficit Cost Allocators**		2016		2017
25	Priority Firm - 7(b) Loads..		0.9926		0.9926
26	Industrial Firm - 7(c) Loads..		0.0074		0.0074
27	New Resources - 7(f) Loads...		0.0000001		0.0000001
28	Surplus Firm - SP Loads...		-1.0000		-1.0000
29	Total...		0.0000		0.0000
30					
31	**Surplus Deficit Cost Allocation**		2016		2017
32	Priority Firm - 7(b) Loads..	$	44,808	$	19,012
33	Industrial Firm - 7(c) Loads..	$	334	$	141
34	New Resources - 7(f) Loads...	$	0.0037	$	0.0015
35	Surplus Firm - SP Loads...	$	(45,142)	$	(19,153)
36	Total...	$	-	$	-
37					
38					
39	**Initial Allocation of Net Revenue Requirement**		2016		2017
40	Priority Firm - 7(b) Loads..	$	4,591,026	$	4,696,994
41	Industrial Firm - 7(c) Loads..	$	51,970	$	52,661
42	New Resources - 7(f) Loads...	$	0.5704	$	0.5779
43	Surplus Firm - SP Loads...	$	41,822	$	37,945
44	Total...	$	4,684,819	$	4,787,600

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2015 - September 2017
($ 000, aMW, $/MWh)

	B		C		D
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2016**		**2017**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,591,026	$	4,696,994
7	Industrial Firm - 7(c) Loads...	$	51,970	$	52,661
8	New Resources - 7(f) Loads...	$	0.5704	$	0.5779
9	Surplus Firm - SP Loads..	$	41,822	$	37,945
10	Total...	$	4,684,819	$	4,787,600
11					
12					
13	**Energy Billing Determinants (aMW)**		**2016**		**2017**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,227		12,295
16	Industrial Firm - 7(c) Loads...		91		91
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2016**		**2017**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		42.75		43.61
23	Industrial Firm - 7(c) Loads...		64.93		65.97
24	New Resources - 7(f) Loads...		64.93		65.97

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8				Embedded Cost $/kW/Mo		$ 7.62		
9								
10	1) Assumed DSI sale					91	aMW	
11	Assumed Wheel Turning Load					6	aMW	
12	Interruptible Load					85		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					9	MW	
15								
16	Total value of Operating Reserves per year					$ 778,632	per year	
17	Value converted to $/MWh on total load					$ 0.973	$/MWh	
18								
19					industrial margin	0.733		
20								
21					**net industrial margin**	**$ (0.240)**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P Q	R	S	T
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7	HLH (mills/kWh)		27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75				
8	LLH (mills/kWh)		23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70				
9	Demand Rate ($/kW/mo)		10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2016**	
13	**2016**	HLH	4982	5613	6329	5906	5489	5522	4778	5375	5127	5264	5510	4703			Energy (GWH)	107399
14		LLH	3108	4004	4391	4298	3569	3573	3097	3594	3174	3503	3280	3211			Allocated Cost	**$ 4,609,703**
15		Demand	593	346	1097	893	620	940	752	463	669	606	868	679			Rate Scalar	**16.48**
16	Revenue at marginal Rates		$ 218,566	$ 261,876	$ 305,464	$ 294,471	$ 257,454	$ 227,606	$ 188,129	$ 185,473	$ 178,593	$ 225,937	$ 256,455	$ 239,601		**$ 2,839,624**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2017**	
18	**2017**	HLH	4950	5755	6373	5919	5433	5566	4798	5395	4949	5271	5543	4749			Energy (GWH)	107703
19		LLH	3197	3961	4437	4392	3575	3592	3233	3512	3052	3506	3301	3242			Allocated Cost	**$ 4,715,789**
20		Demand	505	469	1119	914	574	961	651	610	681	616	884	690			Rate Scalar	**17.32**
21	Revenue at marginal Rates		$ 218,905	$ 266,133	$ 308,110	$ 297,460	$ 255,460	$ 229,350	$ 190,604	$ 185,652	$ 172,483	$ 226,316	$ 258,147	$ 241,998		**$ 2,850,618**		
43																		
50																		
51	**IP Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2016**	
52	**2016**	HLH	39	36	36	38	36	38	38	38	36	37	39	35			Energy (GWH)	800
53		LLH	29	29	32	30	27	30	28	30	29	30	28	31			Allocated Cost	**$ 33,294**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**16.24**
55	Revenue at marginal Rates		$ 1,778	$ 1,760	$ 1,844	$ 1,891	$ 1,744	$ 1,619	$ 1,511	$ 1,358	$ 1,339	$ 1,674	$ 1,885	$ 1,893		**$ 20,295**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2017**	
57	**2017**	HLH	39	36	36	38	35	38	38	38	36	37	39	35			Energy (GWH)	798
58		LLH	29	29	32	30	26	30	28	30	29	30	28	31			Allocated Cost	**$ 33,867**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**17.08**
60	Revenue at marginal Rates		$ 1,778	$ 1,760	$ 1,844	$ 1,891	$ 1,684	$ 1,619	$ 1,511	$ 1,358	$ 1,339	$ 1,674	$ 1,885	$ 1,893		**$ 20,235**		

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2015 - September 2017
($/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
6	HLH (mills/kWh)		27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75				
7	LLH (mills/kWh)		23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70				
8	Demand Rate ($/kW/mo)		10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				
9																		
10																		
11	**Unbifurcated PF/NR**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2016**	HLH	44.34	45.04	45.70	46.50	46.13	41.87	40.84	38.58	39.64	43.91	46.78	48.23				**2016**
13		LLH	40.23	40.96	41.30	41.51	41.16	38.55	37.52	34.01	33.59	38.06	40.89	42.18				**16.48**
14		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2017**	HLH	45.18	45.88	46.54	47.34	46.97	42.70	41.68	39.42	40.47	44.74	47.62	49.07				**2017**
17		LLH	41.07	41.80	42.14	42.35	42.00	39.39	38.36	34.85	34.43	38.90	41.73	43.02				**17.32**
18		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
36																		
42																		
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
44	**2016**	HLH	44.10	44.80	45.46	46.26	45.89	41.63	40.60	38.34	39.40	43.67	46.54	47.99				**2016**
45		LLH	39.99	40.72	41.06	41.27	40.92	38.31	37.28	33.77	33.35	37.82	40.65	41.94				**16.24**
46		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
48	**2017**	HLH	44.94	45.64	46.30	47.10	46.73	42.46	41.44	39.18	40.23	44.51	47.38	48.83				**2017**
49		LLH	40.83	41.56	41.90	42.11	41.76	39.15	38.12	34.61	34.19	38.66	41.49	42.78				**17.08**
50		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2015 - September 2017
($ 000)

	B	C	D	E	F	G	H
4						**FY 2016**	**FY 2017**
5							
6	1 IP Allocated Costs					51,970	52,661
7	2 IP Revenues @ Net Margin					(192)	(191)
8	3 adjustment					541	584
9	4 IP Marginal Cost Rate Revenues					20,295	20,235
10	5 PF/NR Marginal Cost Rate Revenues					2,839,624	2,850,618
11	6 PF/NR Allocated Energy Costs					4,591,027	4,696,994
12	7 Numerator: 1-2-3-((4/5)*6)					18,809	18,928
13	8						
14	9 PF Allocation Factor for Delta					0.999999918	0.999999919
15	10 NR Allocation Factor for Delta					0.000000082	0.000000081
16	11 Total Allocation Factors for Delta					1.000000000	1.000000000
17	12 Denominator: 1.0 + ((9/11)*(4/5))					1.0071	1.0071
18	13						
19	14 DELTA: (7/12)					**18,676**	**18,795**
20							
21						-0.239	-0.239
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2015 - September 2017
($ 000, aMW, $/MWh)

	B	C	D
5	**Initial Allocation of Net Revenue Requirement)**	**2016**	**2017**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,591,026	$ 4,696,994
7	Industrial Firm - 7(c) Loads..	$ 51,970	$ 52,661
8	New Resources - 7(f) Loads...	$ 0.5704	$ 0.5779
9	Surplus Firm - SP Loads...	$ 41,822	$ 37,945
10	Total...	$ 4,684,819	$ 4,787,600
11			
12			
13	**First IP-PF Link Delta**	**$ 18,676**	**$ 18,795**
14			
15			
16	**7(c)(2) Delta Cost Allocators**	**2016**	**2017**
17	Unbifurcated Priority Firm - 7(b) Loads..............................	0.999999918	0.999999919
18	Industrial Firm - 7(c) Loads..	-1.000000000	-1.000000000
19	New Resources - 7(f) Loads...	0.000000082	0.000000081
20			
21	**7(c)(2) Delta Cost Allocation**	**2016**	**2017**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 18,676	$ 18,795
23	Industrial Firm - 7(c) Loads..	$ (18,676)	$ (18,795)
24	New Resources - 7(f) Loads...	$ 0.002	$ 0.002
25	Total...	$ 0	$ (0)
26			
27	**Cost Allocation After 7c2 Delta ($ 000)**	**2016**	**2017**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,609,702	$ 4,715,788
29	Industrial Firm - 7(c) Loads..	$ 33,294	$ 33,867
30	New Resources - 7(f) Loads...	$ 0.572	$ 0.579
31	Surplus Firm - SP Loads...	$ 41,822	$ 37,945
32	Total...	$ 4,684,819	$ 4,787,600
33			
34	**Energy Billing Determinants (aMW)**	**2016**	**2017**
35	Unbifurcated Priority Firm - 7(b) Loads..............................	12,227	12,295
36	Industrial Firm - 7(c) Loads..	91.11868545	91.11889429
37	New Resources - 7(f) Loads...	0.001	0.001
38			
39			
40	**Average Power Rates ($/MWh)**	**2016**	**2017**
41			
42	Unbifurcated Priority Firm - 7(b) Loads..............................	42.92	43.79
43	Industrial Firm - 7(c) Loads..	41.60	42.43
44	New Resources - 7(f) Loads...	65.11	66.15
45			
46			
47	Base PF Exchange Rate w/o Transmission Adder...............	**43.35**	

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J
10		Industrial Firm Power Floor Rate Calculation							
11				**A**	**B**	**C**	**D**	**E**	**F**
12									
13				**DEMAND**		**ENERGY**		**Customer**	**Total/**
14				**Winter**	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
15				(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
16									
17	1	IP Billing Determinants[1]		905	1,272	930	668	2,178	1,599
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		4,182	2,812	13,677	8,152	15,984	44,807
20	4	Exchange Adj Clause for OY 1985							
21	5	New ASC Effective Jul 1, 1984							
22	6	Actual Total Exchange Cost (AEC)		938,442					
23	7	Actual Exchange Revenue (AER)		772,029					
24	8	Forecasted Exchange Cost (FEC)		1,088,690					
25	9	Forecasted Exchange Revenue (FER)		809,201					
26	10	Total Under/Over-recovery (TAR)							
27	11	(TAR=(AEC-AER)-(FEC-FER))		(113,076)					
28	12	Exchange Cost Percentage for IP (ECP)		0.521					
29	13	Rebate or Surcharge for IP (CCEA=TAR*ECP)		(58,913)					
30	14	OY 1985 IP Billing Determinants[2]		24,368					
31	15	OY 1985 DSI Transmission Costs[3]		92,960					
32	16	Adjustment for Transmission Costs[4]		(3.81)					
33	17	Adjustment for the Exchange (mills/kWh)[5]		(2.42)					
34	18	Adjustment for the Deferral (mills/kWh)[6]		(0.90)					
35	19	IP-83 Average Rate (mills/kWh)[7]		28.03					
36	20	Floor Rate (mills/kWh)[8]		20.90					
37									
38		Note 1 - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.							
39		Note 2 - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).							
40		Note 3 - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).							
41		Note 4 - Line 15 / Line 14							
42		Note 5 - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants							
43		Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).							
44		Note 7 - Total Revenue Col F, divided by IP Billing Determinants, Col F							
45		Note 8 - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19							

Rate Directive Step
IP Floor Rate Test
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I
8								
9								
10								
11		Industrial Firm Power Floor Rate Test						
12						**A**	**B**	**C**
13								
14								
15						**Total**		**Average**
16						**Energy**	**TOTALS**	**Rate**
17								
18								
19	1	IP Billing Determinants				1,599		
20	2	Floor Rate (mills/kWh)				20.90		
21	3	Value of Reserves Credit (mills/kWh)						
22	4	Revenue at Floor Rate Less VOR Credit				33,412	33,412	20.90
23	5	IP Revenue Under Proposed Rates					67,161	42.01
24	6	Difference[1]					0	
25								
26		Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.						
27								

Rate Directive Step
Calculation of IOU and COU Base PF Exchange Rates
Test Period October 2015 - September 2017

	B	C	D		E		F
9		**Cost Allocation After 7c2 Delta**		**2016**		**2017**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.............................	$	4,609,702	$	4,715,788	$ 9,325,491
11							
12		Exchange Unbifurcated Costs to 7(b) Loads.......................	$	2,005,909	$	2,048,625	$ 4,054,533
13							
14							
15							
16							
17		**Energy Billing Determinants (aMW)**		**2016**		**2017**	
18		Unbifurcated Priority Firm - 7(b) Loads.............................		5,320		5,341	
19							
20							
21		**Average Power Rates**		**2016**		**2017**	
22							
23		Unbifurcated Priority Firm - 7(b) Loads.............................		42.92		43.79	
24							
25							
26				(GWh)			
27		Two Year PF Public Load T1		120286			
28		Two Year PF Public Load T2		1292			
29		Two Year IOU PF Exchange Load		81125			
30		Two Year COU PF Exchange Load		12397			
31		Total Two-Year Unbifurcated PF Load		215101			
32							
33							
34		T 2 Costs	$	50,373			
35		T 1 Costs	$	9,275,117			
36		Total	$	9,325,491			
37							
45		Total PF Costs Minus PF T2 Costs	$	9,275,117			
46		Total PF Load Minus PF T2 Load		213,809			
47		COU Base PF w/o Transmission		43.38			
48		Exchange Transmission Adder		4.60			
49		**COU Base PFx**		**47.98**			
50							
51							
52		Two Year COU PF Exchange Load		12397			
53		Two Year Base PF Public Exchange T2 Revenue	$	537,803			
54							
55		Total Exchange Costs minus COU Exchange Costs	$	3,516,731			
56		Total IOU Exchange Loads		81,125			
57		IOU Base PF w/o Transmission		43.35			
58		Exchange Transmission Adder		4.60			
59		**IOU Base PFx**		**47.95**			
60							

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2015 - September 2017

	B	C		D	
8					
9	EOFY 2011 Lookback Amount		($510,030)		
10					
11	Mortgage Payment Variables				
12	PMT Interest Rate		0.0425		
13	Number of Periods		8		
14					
15	Annual Lookback Mortgage Payment		$76,537.617		
16					
17					
18	IOU Scheduled Amount		$214,100		
19	Refund Amount*		$76,538		
20	REP Recovery Amount		$290,638		
21					
26					
27					
28			**2016**		**2017**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	785,696	$	785,696
31	REP Recovery Amount	**$**	**290,638**	**$**	**290,638**
32	Rate Protection Delta	$	495,058	$	495,058
33					
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*				

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**47.95**									
6	**COU Base PFx**	**47.98**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2016**	**2017**		**2016**	**2017**		**2016**	**2017**
9											
10											
11	Avista Corporation	1		50.87	50.87		3,897	3,897		$ 11,382	$ 11,382
12	Idaho Power Company	1		59.02	59.02		6,763	6,763		$ 74,872	$ 74,872
13	NorthWestern Energy,	1		79.24	79.24		679	679		$ 21,240	$ 21,240
14	PacifiCorp	1		76.42	76.42		9,006	9,006		$ 256,400	$ 256,400
15	Portland General Elect	1		71.14	71.14		8,600	8,600		$ 199,438	$ 199,438
16	Puget Sound Energy, I	1		67.09	67.09		11,617	11,617		$ 222,364	$ 222,364
17	Clark Public Utilities	1		50.95	50.95		2,388	2,377		$ 7,090	$ 7,060
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish County PU	1		49.59	49.85		3,784	3,848		$ 6,091	$ 7,194
31	Total									**$ 798,877**	**$ 799,950**
32											
33									IOU	**$ 785,696**	**$ 785,696**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY 2016**	**FY 2017**	**Average**				**Interim**	**Refund**	**Interim**	**Interim**	**Interim**
5				**Base**	**Exchange**	**Exchange**	**Exchange**	**Unconstrained**	**Scheduled**	**Refund**	**Protection**	**Cost**	**7(b)(3)**	**Utility**	**REP**
6			**ASC**	**PFx**	**Load**	**Load**	**Load**	**Benefits**	**Amount**	**Amount**	**Allocation**	**Allocation**	**Surcharge**	**PFx**	**Benefits**
7			a	b	c	d	e=avg(c,d)	f=(a-b)*e	g=contract	h=contract	Σi=Σf - Σh	Σj=h	k=(i+j)/e	l=b+k	m=(a-l)*e
8	Avista Corporation	1	50.87	47.95	3,897	3,897	3,897	$ 11,382			$ 7,172	$ 1,109	2.12	50.07	$ 3,102
9	Idaho Power Company	1	59.02	47.95	6,763	6,763	6,763	$ 74,872			$ 47,176	$ 7,294	8.05	56.00	$ 20,402
10	NorthWestern Energy, LLC	1	79.24	47.95	679	679	679	$ 21,240			$ 13,383	$ 2,069	22.76	70.71	$ 5,788
11	PacifiCorp	1	76.42	47.95	9,006	9,006	9,006	$ 256,400			$ 161,555	$ 24,977	20.71	68.66	$ 69,868
12	Portland General Electric Company	1	71.14	47.95	8,600	8,600	8,600	$ 199,438			$ 125,664	$ 19,428	16.87	64.82	$ 54,346
13	Puget Sound	1	67.09	47.95	11,617	11,617	11,617	$ 222,364			$ 140,109	$ 21,661	13.92	61.87	$ 60,594
14	Clark Public Utilities	1	50.95	47.98	2,388	2,377	2,383	$ 7,075			$ 4,458		1.87	49.85	$ 2,617
15	Franklin	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish County PUD No 1	1	49.59	47.98	3,784	3,848	3,816	$ 6,142			$ 3,870		1.01	48.99	$ 2,272
17	Total							$ 798,913	$214,100	$76,538	$ 503,386	$76,538			$ 218,989
18															
19	rounding to 4 places = -$125						IOU Σ(g)	$ 785,696	$214,100	$290,638	$ 495,058	IOU Σ(j)		IOU REP	$ 214,100
20							COU Σ(g)	$ 13,218		$4,889	$ 8,328	COU Σ(j)		COU REP	$ 4,889
21															
22	**IOU Reallocations**														
23			**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2016**	**FY 2017**
24			**REP**	**Annual**	**Reallocation**	**Reallocated**	**Protection**	**7(b)(3)**	**Utility**		**REP**			**REP**	**REP**
25			**Benefits**	**Adjustment**	**Adjustment**	**Benefits**	**Allocation**	**Surcharge**	**PFx**		**Benefits**			**Benefits**	**Benefits**
26			n=m	o=contract	p=below	q=n-o+p	r=f-q	s=r/e	t=b+s		u=(a-t)*e			v=(a-t)*c	w=(a-t)*d
27	Avista Corporation		$ 3,102	$ 2,005	$ 157	$ 1,254	$ 10,128	2.60	50.54820		$ 1,254		Avista	$ 1,254	$ 1,254
28	Idaho Power Company		$ 20,402	$ 10,201	$ -	$ 10,201	$ 64,671	9.56	57.51170		$ 10,201		Idaho Power	$ 10,201	$ 10,201
29	NorthWestern Energy, LLC		$ 5,788	$ (383)	$ 781	$ 6,952	$ 14,288	21.05	68.99820		$ 6,952		NorthWestern	$ 6,952	$ 6,952
30	PacifiCorp		$ 69,868	$ 8,443	$ 3,546	$ 64,972	$ 191,428	21.26	69.20550		$ 64,972		PacifiCorp	$ 64,972	$ 64,972
31	Portland General Electric Company		$ 54,346	$ -	$ 7,461	$ 61,808	$ 137,630	16.00	63.95300		$ 61,808		Portland	$ 61,808	$ 61,808
32	Puget Sound		$ 60,594	$ -	$ 8,319	$ 68,913	$ 153,451	13.21	61.15820		$ 68,912		Puget Sound	$ 68,912	$ 68,912
33	Total		$ 214,100	$ 20,266	$ 20,266	$ 214,100	$ 571,596				$ 214,100		IOU REP	$ 214,100	$ 214,100
34															
35													Clark	$ 2,623	$ 2,612
36													Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ 2,253	$ 2,291
38			Avista Corporati	o Power Com	Western Energy	PacifiCorp	eneral Electri	Puget Sound	Total				COU REP	$ 4,876	$ 4,903
39			$ 2,005	$ 10,201	$ (383)	$ 8,443	$ -	$ -					Total REP	$ 218,976	$ 219,003
40			p1=o1*(f/Σf)	p2=o2*(f/Σf)	p3=o3*(f/Σf)	p4=o4*(f/Σf)	p5=o5*(f/Σf)	p6=o6*(f/Σf)	p=Σ(p1…p6)						
41	Avista Corporation			$ 164	$ (6)				$ 157				Refund Amt	$ 76,538	$ 76,538
42	Idaho Power Company								$ -				REP Cost	$ 295,513	$ 295,540
43	NorthWestern Energy, LLC		$ 96	$ 280		$ 405	$ -	$ -	$ 781						
44	PacifiCorp			$ 3,689	$ (142)				$ 3,546						
45	Portland General Electric Company		$ 902	$ 2,869	$ (111)	$ 3,801			$ 7,461						
46	Puget Sound		$ 1,006	$ 3,199	$ (124)	$ 4,237	$ -		$ 8,319						
47			$ 2,005	$ 10,201	$ (383)	$ 8,443	$ -	$ -	$ 20,266						

Rate Directive Step
IOU Reallocation Balances
Test Period October 2015 - September 2017

	B	C	D	E	F	G
4	**2012 REP Settlement Agreement Section 6 Reallocations**					
5						
6		**Initital Amount**	**Max Annual**		**Receiving Utilities**	
7	Avista Corporation	$ 22,985,810	$ 2,004,778		NWE, PGE, PSE	
8	Idaho Power Company -- total	$ 45,140,170				
9	Idaho Power Company -- 92%	$ 41,528,956	50% of benefits		AVA, NWE, PAC, PGE, PSE	
10	Idaho Power Company -- 8%	$ 3,611,214	50% of benefits		AVA, PAC, PGE, PSE	
11	NorthWestern Energy, LLC	N/A	N/A		AVA, IDA, PAC, PGE, PSE	
12	PacifiCorp	$ 66,721,315	$ 8,442,636		NWE, PGE, PSE	
13	Portland General Electric Company	$ 4,669,222	$ 1,237,583		NWE, PSE	
14	Puget Sound	N/A	N/A		NWE	
15						
16			**Max Annual**	**Max Annual**		
17	**Section 6.2.4 Adjustment**	**Initital Amount**	**2012–2015**	**2016–2017**	**Paying Utilities**	
18	NorthWestern Energy, LLC	$ (3,830,000)	$ (766,000)	$ (383,000)	AVA, PAC, PGE, PSE	
19						
20						
21						
22		**FY2012 Realloc**	**Accrued Interest**	**FY2013 Realloc**	**Accrued Interest**	**Remain Balance**
23	Avista Corporation	$ 2,004,778	$ 659,503	$ 2,004,778	$ 619,144	$ 20,254,901
24	Idaho Power Company	$ 2,521,193	$ 1,316,387	$ 2,521,193	$ 1,280,243	$ 42,694,414
25	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (2,298,000)
26	PacifiCorp	$ 8,442,636	$ 1,875,000	$ 8,442,636	$ 1,677,971	$ 53,389,014
27	Portland General Electric Company	$ 1,237,583	$ 121,513	$ 1,237,583	$ 88,031	$ 2,403,600
28						
29		**FY2014 Realloc**	**Accrued Interest**	**FY2015 Realloc**	**Accrued Interest**	**Remain Balance**
30	Avista Corporation	$ 2,004,778	$ 577,575	$ 2,004,778	$ 534,759	$ 17,357,680
31	Idaho Power Company	$ 3,001,474	$ 1,235,810	$ 3,001,474	$ 1,182,840	$ 39,110,117
32	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (766,000)
33	PacifiCorp	$ 8,442,636	$ 1,475,031	$ 8,442,636	$ 1,266,003	$ 39,244,775
34	Portland General Electric Company	$ 1,237,583	$ 53,544	$ 1,237,583	$ 18,023	$ -
35						
36		**FY2016 Realloc**	**Accrued Interest**	**FY2017 Realloc**	**Accrued Interest**	**Remain Balance**
37	Avista Corporation	$ 2,004,778	$ 490,659	$ 2,004,778	$ 445,235	$ 14,284,017
38	Idaho Power Company	$ 3,001,474	$ 1,128,281	$ 3,001,474	$ 1,072,086	$ 35,307,537
39	NorthWestern Energy, LLC	$ (383,000)	$ -	$ (383,000)	$ -	$ -
40	PacifiCorp	$ 8,442,636	$ 1,050,704	$ 8,442,636	$ 828,946	$ 24,239,153
41	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
42						
43		**FY2018 Realloc**	**Accrued Interest**	**FY2019 Realloc**	**Accrued Interest**	**Remain Balance**
44	Avista Corporation	$ 2,004,778	$ 398,449	$ 2,004,778	$ 350,259	$ 11,023,169
45	Idaho Power Company	$ 3,001,474	$ 1,014,204	$ 3,001,474	$ 954,586	$ 31,273,379
46	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
47	PacifiCorp	$ 8,442,636	$ 600,535	$ 8,442,636	$ 365,272	$ 8,319,688
48	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
49						
50		**FY2020 Realloc**	**Accrued Interest**	**FY2021 Realloc**	**Accrued Interest**	**Remain Balance**
51	Avista Corporation	$ 2,004,778	$ 300,623	$ 2,004,778	$ 249,499	$ 7,563,736
52	Idaho Power Company	$ 3,001,474	$ 893,179	$ 3,001,474	$ 829,930	$ 26,993,541
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ -	$ 249,591	$ -	$ 257,078	$ 8,826,357
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57						

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2015 - September 2017

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2016**		**2017**
5	Priority Firm Public - 7(b) Loads...	$	2,603,794	$	2,667,164
6	Priority Firm Exchange - 7(b) Loads....................................	$	2,005,909	$	2,048,625
7	Industrial Firm - 7(c) Loads...	$	33,294	$	33,867
8	New Resources - 7(f) Loads...	$	0.572	$	0.579
9	Surplus Firm - SP Loads..	$	41,822	$	37,945
10	Total..	$	4,684,819	$	4,787,600
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2016**		**2017**
14	Unconstrained Benefits	$	798,877	$	799,950
15	REP Recovery Amount plus COU Benefits	$	(295,513)	$	(295,540)
16	delta	$	503,364	$	504,410
17					
18					
19	**Allocation Factors**		**2016**		**2017**
20	Priority Firm Public - 7(b) Loads...		-1.0000000		-1.0000000
21	Priority Firm Exchange - 7(b) Loads....................................		1.0000000		1.0000000
22	Industrial Firm - 7(c) Loads...		0.0000000		0.0000000
23	New Resources - 7(f) Loads...		0.0000000		0.0000000
24					
25					
26	**Allocation of Rate Protection Cost**		**2016**		**2017**
27	Priority Firm Public - 7(b) Loads...	$	(503,364)	$	(504,410)
28	Priority Firm Exchange - 7(b) Loads....................................	$	503,364	$	504,410
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2016**		**2017**
35	Priority Firm Public - 7(b) Loads...	$	2,100,430	$	2,162,754
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,509,272	$	2,553,034
37	Industrial Firm - 7(c) Loads...	$	33,294	$	33,867
38	New Resources - 7(f) Loads...	$	0.572	$	0.579
39	Surplus Firm - SP Loads..	$	41,822	$	37,945
40	Total..	$	4,684,819	$	4,787,600
41					
42					
43	**Energy Billing Determinants (aMW)**		**2016**		**2017**
44	Priority Firm Public - 7(b) Loads...		6,906		6,954
45	Priority Firm Exchange - 7(b) Loads....................................		5,320		5,341
46	Industrial Firm - 7(c) Loads...		91		91
47	New Resources - 7(f) Loads...		0.001		0.001
48					
50					
51	**Average Power Rates**		**2016**		**2017**
52	Priority Firm Public - 7(b) Loads...		34.62		35.51
53	Priority Firm Exchange - 7(b) Loads....................................		58.29		59.17
54	Industrial Firm - 7(c) Loads...		41.60		42.43
55	New Resources - 7(f) Loads...		65.11		66.15

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2015 - September 2017

	B		C		D
25			**2016**		**2017**
26	WP-10 Average IOU REP Benefits (before Lookback recovery	$	265,847	$	265,847
27					
28	WP-10 7b3 Supplemental Rate Charge	$	7.38	$	7.38
29	IP/NR REP Surcharge	$	8.20	$	8.20
30	IP Load		800		798
31	NR Load		0		0
32	REP Surharge Revenue from IP Rate	$	6,566	$	6,549
33	REP Surharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surchar	$	288,947	$	288,991
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.70	$	4.68
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	10,329	$	10,287
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	6,481	$	6,464
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2016**		**2017**
48	Priority Firm Public - 7(b) Loads...	$	285,185	$	285,254
49	Industrial Firm - 7(c) Loads..	$	10,329	$	10,287
50	New Resources - 7(f) Loads..	$	0.113	$	0.113
51		$	295,513	$	295,540
52					
53	Adjustment Necessary to Achieve Reallocation		**2016**		**2017**
54	Priority Firm Public - 7(b) Loads...	$	(6,481)	$	(6,464)
55	Industrial Firm - 7(c) Loads..	$	6,481	$	6,464
56	New Resources - 7(f) Loads..	$	0.071	$	0.071
57		$	(0)	$	(0)
58					
59			**2016**		**2017**
60	PF Contribution to Net REP Benefits $/MWh...........................		4.70		4.68
61	IP Contribution to Net REP Benefits $/MWh............................		12.90		12.89
62	NR Contribution to Net REP Benefits $/MWh..........................		12.90		12.89

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2015 - September 2017

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2016**		**2017**
5	Priority Firm Public - 7(b) Loads..	$	2,100,430	$	2,162,754
6	Priority Firm Exchange - 7(b) Loads..	$	2,509,272	$	2,553,034
7	Industrial Firm - 7(c) Loads..	$	33,294	$	33,867
8	New Resources - 7(f) Loads...	$	0.572	$	0.579
9	Surplus Firm - SP Loads...	$	41,822	$	37,945
10	Total...	$	4,684,819	$	4,787,600
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2016**		**2017**
15	Priority Firm Public - 7(b) Loads..	$	(6,481)	$	(6,464)
16					
17	Industrial Firm - 7(c) Loads..	$	6,481	$	6,464
18	New Resources - 7(f) Loads...	$	0.071	$	0.071
19	Total...	$	(0)	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2016**		**2017**
23	Priority Firm Public - 7(b) Loads..	$	2,093,949	$	2,156,290
24	Priority Firm Exchange - 7(b) Loads..	$	2,509,272	$	2,553,034
25	Industrial Firm - 7(c) Loads..	$	39,775	$	40,331
26	New Resources - 7(f) Loads...	$	0.643	$	0.650
27	Surplus Firm - SP Loads...	$	41,822	$	37,945
28	Total...	$	4,684,819	$	4,787,600
29					
30					
31	**Energy Billing Determinants (aMW)**		**2016**		**2017**
32	Priority Firm Public - 7(b) Loads..		6,906		6,954
33	Priority Firm Exchange - 7(b) Loads..		5,320		5,341
34	Industrial Firm - 7(c) Loads..		91		91
35	New Resources - 7(f) Loads...		0.001		0.001
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2016**		**2017**
40	Priority Firm Public - 7(b) Loads..		34.52		35.40
41	Priority Firm Exchange - 7(b) Loads..		58.29		59.17
42	Industrial Firm - 7(c) Loads..		49.70		50.53
43	New Resources - 7(f) Loads...		73.20		74.25

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
5																		
6		**Load Shaping Rate**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
7		HLH (mills/kWh)	27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75				
8		LLH (mills/kWh)	23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70				
9		Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				
10																		
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2016**	
12	**2016**	HLH	2814	3170	3575	3336	3101	3119	2699	3036	2896	2973	3112	2656			Energy (GWH)	60664
13		LLH	1756	2262	2481	2427	2016	2018	1749	2030	1793	1979	1853	1814			Allocated Cost	$ 2,100,505
14		Demand	335	195	620	504	350	531	425	262	378	342	490	383			Rate Scalar	**8.19**
15		Revenue at marginal Rates	$ 123,457	$ 147,921	$ 172,541	$ 166,332	$ 145,423	$ 128,563	$ 106,265	$ 104,764	$ 100,878	$ 127,620	$ 144,859	$ 135,339		$ 1,603,964		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2017**	
17	**2017**	HLH	2800	3255	3604	3348	3073	3148	2714	3051	2799	2981	3135	2686			Energy (GWH)	60915
18		LLH	1808	2240	2510	2484	2022	2031	1829	1987	1726	1983	1867	1834			Allocated Cost	$ 2,162,815
19		Demand	286	265	633	517	325	544	368	345	385	349	500	390			Rate Scalar	**9.04**
20		Revenue at marginal Rates	$ 123,809	$ 150,520	$ 174,261	$ 168,238	$ 144,484	$ 129,716	$ 107,802	$ 105,002	$ 97,553	$ 128,000	$ 146,003	$ 136,869		$ 1,612,257		
21			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22																		
23																		
24																		
25		**IP Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2016**	
26	**2016**	HLH	39	36	36	38	36	38	38	38	36	37	39	35			Energy (GWH)	800
27		LLH	29	29	32	30	27	30	28	30	29	30	28	31			Allocated Cost	$ 33,220
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**16.15**
29		Revenue at marginal Rates	$ 1,778	$ 1,760	$ 1,844	$ 1,891	$ 1,744	$ 1,619	$ 1,511	$ 1,358	$ 1,339	$ 1,674	$ 1,885	$ 1,893		$ 20,295		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2017**	
31	**2017**	HLH	39	36	36	38	35	38	38	38	36	37	39	35			Energy (GWH)	798
32		LLH	29	29	32	30	26	30	28	30	29	30	28	31			Allocated Cost	$ 33,806
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**17.00**
34		Revenue at marginal Rates	$ 1,778	$ 1,760	$ 1,844	$ 1,891	$ 1,684	$ 1,619	$ 1,511	$ 1,358	$ 1,339	$ 1,674	$ 1,885	$ 1,893		$ 20,235		
35																		

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2015 - Septmentber 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
6	HLH (mills/kWh)		27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75				
7	LLH (mills/kWh)		23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70				
8	Demand Rate ($/kW/mo)		10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				
9																		
10																		
11	**Unbifurcated PF /NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2016**	HLH	36.05	36.75	37.41	38.20	37.84	33.57	32.54	30.28	31.34	35.61	38.48	39.94				**2016**
13		LLH	31.94	32.67	33.01	33.22	32.87	30.26	29.23	25.72	25.30	29.77	32.60	33.89				**8.19**
14		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2017**	HLH	36.90	37.60	38.26	39.06	38.69	34.42	33.40	31.14	32.19	36.47	39.34	40.79				**2017**
17		LLH	32.79	33.52	33.86	34.07	33.72	31.11	30.08	26.57	26.15	30.62	33.45	34.74				**9.04**
18		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2016**	HLH	44.01	44.71	45.37	46.17	45.80	41.53	40.51	38.25	39.30	43.58	46.45	47.90				**2010**
23		LLH	39.90	40.63	40.97	41.18	40.83	38.22	37.19	33.68	33.26	37.73	40.56	41.85				**16.15**
24		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2017**	HLH	44.86	45.56	46.22	47.02	46.66	42.39	41.36	39.10	40.16	44.43	47.30	48.75				**2011**
27		LLH	40.75	41.48	41.82	42.03	41.68	39.07	38.04	34.53	34.11	38.58	41.41	42.70				**17.00**
28		Demand	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42				**Scalar**

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H
4						**FY 2016**	**FY 2017**
5							
6	1	IP Allocated Costs				33,294	33,867
7	2	IP Revenues @ Net Margin				(192)	(191)
8	3	adjustment				354	389
9	4	IP Marginal Cost Rate Revenues				20,295	20,235
10	5	PF/NR Marginal Cost Rate Revenues				1,603,964	1,612,257
11	6	PF Allocated Energy Costs				2,093,950	2,156,290
12	7	Numerator: 1-2-3-((4/5)*6)				6,638	6,606
13	8						
14	9	PF Allocation Factor for Delta				0.999999918	0.999999919
15	10	NR Allocation Factor for Delta				0.000000082	0.000000081
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0127	1.0126
18	13						
19	14	DELTA: (7/12)				**6,555**	**6,525**
20							
21						-0.240	-0.240
22							

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2015 - September 2017

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2016**	**2017**	
5	Priority Firm Public - 7(b) Loads	$ 2,093,949	$ 2,156,290	
6	Priority Firm Exchange - 7(b) Loads	$ 2,509,272	$ 2,553,034	
7	Industrial Firm - 7(c) Loads	$ 39,775	$ 40,331	
8	New Resources - 7(f) Loads	$ 0.643	$ 0.650	
9	Surplus Firm - SP Loads	$ 41,822	$ 37,945	
10	Total	$ 4,684,819	$ 4,787,600	
11				
12				
13	IP-PF Link Delta	$ 6,555	$ 6,525	
14				
15		**2016**	**2017**	
16	Priority Firm Public - 7(b) Loads	0.99999986	0.99999986	
17	Industrial Firm - 7(c) Loads	(1.00000000)	(1.00000000)	
18	New Resources - 7(f) Loads	0.00000014	0.00000014	
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2016**	**2017**	
22	Priority Firm Public - 7(b) Loads	$ 6,555	$ 6,525	
23	Priority Firm Exchange - 7(b) Loads	$ -	$ -	
24	Industrial Firm - 7(c) Loads	$ (6,555)	$ (6,525)	
25	New Resources - 7(f) Loads	$ 0.001	$ 0.001	
26	Total	$ (0)	$ 0	
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2016**	**2017**	
30	Priority Firm Public - 7(b) Loads	$ 2,100,504	$ 2,162,814	
31	Priority Firm Exchange - 7(b) Loads	$ 2,509,272	$ 2,553,034	
32	Industrial Firm - 7(c) Loads	$ 33,220	$ 33,806	
33	New Resources - 7(f) Loads	$ 0.644	$ 0.651	
34	Surplus Firm - SP Loads	$ 41,822	$ 37,945	
35	Total	$ 4,684,819	$ 4,787,600	
36				
37				
38	**Energy Billing Determinants (aMW)**	**2016**	**2017**	
39	Priority Firm Public - 7(b) Loads	6,906	6,954	
40	Priority Firm Exchange - 7(b) Loads	5,320	5,341	
41	Industrial Firm - 7(c) Loads	91	91	
42	New Resources - 7(f) Loads	0.001	0.001	
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2016**	**2017**	Average
47	Priority Firm Public - 7(b) Loads	34.63	35.51	**35.07**
48	Priority Firm Exchange - 7(b) Loads	58.29	59.17	**58.73**
49	Industrial Firm - 7(c) Loads	41.50	42.35	**41.93**
50	New Resources - 7(f) Loads	73.31	74.35	**73.83**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2015 to September 2017

	B	D	E	F	G	H	I	J	K	L
4		**2016**	**2017**	**Avg**				**2016**	**2017**	**Avg**
5	Resource Costs	3,039,959	3,043,605	3,041,782			PFx Alloc Cost	(2,509,272)	(2,553,034)	
6	PFx Revenues	(2,724,251)	(2,768,259)	(2,746,255)			Exch Tmn Cost	(214,978)	(215,225)	
7	REP Benefits	315,708	275,345	295,527				(2,724,251)	(2,768,259)	(2,746,255)
8										
9	**REP Benefits**						**PFx Revenues**			
10	Avista Corporation	1,254	1,254				Avista Corporation	197,003	197,004	
11	Idaho Power Company	10,201	10,201				Idaho Power Company	388,963	388,963	
12	NorthWestern Energy, LLC	6,952	6,952				NorthWestern Energy, LLC	46,836	46,836	
13	PacifiCorp	64,972	64,972				PacifiCorp	623,251	623,251	
14	Portland General Electric Company	61,808	61,808				Portland General Electric Compai	549,994	549,995	
15	Puget Sound Energy, Inc.	68,912	68,912				Puget Sound Energy, Inc.	710,502	710,501	
16	IOU REP	214,100	214,100	214,100			IOU REP	2,516,549	2,516,549	2,516,549
17										
18	Clark Public Utilities	2,623	2,612				Clark Public Utilities	119,030	118,521	
19	Franklin	-	-				Franklin	-	-	
20	Snohomish County PUD No 1	2,253	2,291				Snohomish County PUD No 1	185,404	188,531	
21	COU REP	4,876	4,903	4,889			COU REP	304,435	307,053	305,744
22										
23	Refund Amounts	76,538	76,538				Refund Amounts	(76,538)	(76,538)	
24	Total REP	295,513	295,540	295,527			Total REP	2,744,446	2,747,064	2,745,755
25				0				20,195	(21,195)	(500)
26										
27	**For Slice True-Up**									99.98%
28	IOU REP	214,100	214,100							
29	COU REP	4,876	4,903							
30	Refund Amounts	76,538	76,538							
31	Total REP	295,513	295,540							

Table 2.5.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	G	H
4						**2016**	**2017**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	584,274	597,536
9					Interest	159,008	159,561
10					MRNR	-	0
11				Fish & Wildlife			
12					Operating Expense	311,377	321,271
13					Interest	14,239	15,559
14					MRNR	-	-
15				Trojan		800	800
16				WNP #1		259,125	202,867
17				Columbia Generating Station		363,758	449,939
18				WNP #3		225,942	256,332
19				Augmentation		-	20,960
20			Residentail Exchange Program				
21				REP Net Cost		295,513	295,540
22				Program Support		920	635
23				Settlement Interest Accrual		-	-
24			NewResources				
25				Cowlitz		11,600	11,851
26				Idaho		5,015	5,095
27				Tier 1 Aug (Klondike III)		12,493	12,603
28				Other		42,377	37,331
29			Conservation				
30				Operating Expense		205,821	201,537
31				Interest		16,583	15,623
32				MRNR		-	-
33			BPAPrograms				
34				Operating Expense		65,239	37,685
35				Interest		1,925	1,459
36				MRNR		-	-
38			Transmission				
39				Transmission and Ancillary Services		47,957	47,147
40				General Transfer Agreements		63,567	76,521
41			Nonslice Interest and MRNR Allocated to Cost Pools				
42				Interest on BPA fund Credit to Nonslice		2,634	3,094
43				Accrual Revenue (MRNR Adjustment)		-	-
44			**Total**			**2,690,168**	**2,770,947**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	G	H
4						**2016**	**2017**
45		**Non-Slice**					
46			FBS				
47				Balancing Purchases from Risk Mod		14,406	13,598
48				Balancing in Revenue Requirement		8,936	38,663
49				PNRR			
50					Hydro	-	-
51					Fish & Wildlife	-	-
52			Conservation				
53				PNRR		-	-
54			BPAPrograms				
55				Hedging Mitigation		-	-
56				Bad Debt		-	-
57				PNRR		-	-
58			Transmission				
59				Transmission and Ancillary Services		73,093	69,735
60				Third-party T&A		2,381	2,428
61			Nonslice Interest and MRNR				
62				BPA Fund		(2,634)	(3,094)
63				Non-Slice MRNR Adjustment		-	-
64			**Total**			**96,182**	**121,330**
65		**Slice**					
66			BPAPrograms				
67				Other Slice Costs		-	-
68			**Total**			-	-
69		**Tier 2**					
70			FBS				
71				Tier 2 Purchase Costs		22,058	26,582
72				Tier 2 Rate Design Adjustments		808	926
73				Tier 2 Other Costs		-	-
74			**Total**			**22,866**	**27,508**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	G	H
4						**2016**	**2017**
75		**Rate Direct/Design Adjustments**					
76			Credits Allocated Against Cost Pools				
77				FBS (excluding T2 Adjustment)		(112,926)	(109,605)
78				Contract Obligations		(2,493)	(1,972)
79				New Resources		(1,151)	(648)
80				Conservation		(15,000)	(7,000)
81				BPAPrograms		-	-
82				Transmission		(5,750)	(5,800)
83							
84			Secondary Energy Credit (includes pre-sale)			(457,461)	(480,890)
85			Generation Inputs Credit			(115,750)	(115,750)
86			NR Revenues from ESS services			(356)	(356)
87			Composite revenues associated with firm surplus sales			(34,537)	(34,537)
88			Non-slice revenues associated with firm surplus sales			(7,850)	(3,973)
89							
90			Low Density Discount			39,865	40,464
91			Irrigation Rate Mitigation Costs			22,146	22,146
92							
93			Composite Augmentation RSS Revenue Debit/(Credit)			(1,725)	(1,725)
94			Composite Tier 2 RSS Revenue Debit/(Credit)			(83)	(91)
95			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(725)	(835)
96			Composite Non-Federal RSS Revenue Debit/(Credit)			(1,241)	(1,652)
97			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(720)	(720)
98			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			-	-
99			Non-Slice Tier 2 Rate Design Debit/(Credit)			-	-
100			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			69	(26)
101							
102			Firm Surplus and Secondary Credit (from unused RHWM)			(5,991)	(2,744)
103			Demand Revenue			47,946	48,763
104			Load Shaping Revenue			4,040	11,564
105							

Table 2.5.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2015 to September 2017

	B	C		D	
4			**2016**		**2017**
5	Secondary (aMW)		2,293		2,191
6	T1SFCO (aMW)		6,924		6,924
7	RHWM Augmentation (aMW)		59		59
8	RP Augmentation (aMW)		-		-
9	System Augmentation (aMW)		-		81
10	Augmentation Base (aMW)		59		140
11	IP and NR Loads contributing to avoided cost		94		94
12					
13	Value of Secondary	$	21.29	$	23.20
14	Value of T1SFCO ($/MWh)	$	25.53	$	25.53
15	Value of Augmentation	$	27.47	$	29.63
16					
17	Secondary (MWh)		20,142,513		19,196,172
18	T1SFCO (MWh)		60,820,223		60,654,047
19	RHWM Augmentation (MWh)		519,196		517,777
20	Augmentation Base (MWh)		519,196		1,225,235
21	IP and NR Loads (MWh)		824,895		822,643
22					
23	Unused RHWM (MWh)		1,182,765		852,062
24					
25	Unused Secondary		388,394		267,383
26	Unused T1SFCO		1,172,754		844,850
27	Unused Augmentation		10,011		7,212
28					
29	Value of Unused	$	38,486,825	$	27,988,647
30	Value of System Augmentation not Purchased	$	32,495,962	$	25,244,833
31					
32	Net Credit/(Cost)	$	5,990,863	$	2,743,813
33					
34	$/MWh value of Unused RHWM	**$**	**32.67**		

Table 2.5.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
5	Non Slice Loads (MWh)	43,752,017	44,228,843
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	831,288	840,348
8	Average Slice&Non-Slice Tier 1 Rate	35.03	35.03
9	Implied Cost/Credit ($1000)	29,120	29,437

Table 2.5.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2015 - September 2017

	A	B	C	E	F	G
4				**2016**	**2017**	
5		**Table 3.1**				
6			Regulated	6,311	6,388	
7			Independent	353	353	
8		**Table 3.2**				
9			Ashland Solar Project	0	0	
10			Columbia Generating Station	1,075	916	
11			Condon Wind Project	10	10	
12			Dworshak/Clearwater Small Hydropower	3	3	
13			Elwha Hydro	-	-	
14			Foote Creek 1	4	4	
15			Foote Creek 2	-	-	
16			Foote Creek 4	4	4	
17			Fourmile Hill Geothermal	-	-	
18			Georgia-Pacific Paper (Wauna)	11	-	
19			Glines Canyon Hydro	-	-	
20			Klondike I	7	7	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	137	137	
24			Libby Coordination	-	-	
25			BC Hydro Power Purchase	1	1	
26			Pasadena Capacity	-	-	
27			Pasadena Seasonal	-	-	
28			Pasadena Exchange Energy	-	-	
29			PacifiCorp (So Idaho)	-	-	
30			Riverside Capacity	2	-	
31			Riverside Seasonal	4	-	
32			Riverside Exchange Energy	7	-	
33			Sierra Pacific (Wells)	-	-	
34			PacifiCorp	4	4	
35		**Table 3.4**				
36			USBR Pump Load	183	184	
37			Canadian Entitlement	471	468	
38			Non-Treaty Storage	12	12	
39			Libby Coordination	-	-	
40			Hungry Horse	7	5	
41			Riverside Capacity	2	-	
42			Riverside Seasonal	-	-	
43			Pasadena Capacity	-	-	
44			Pasadena Seasonal	-	-	
45			Sierra Pacific (Wells)	-	-	
46			Intertie Losses	0.1	-	
47			WNP3	89	90	
48			PacifiCorp	4	4	
49			PacifiCorp (So Idaho)	-	-	
50			Upper Baker	1	1	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	6,906	6,954	
55			Tier 2	68	79	
56			Net Preference	6,838	6,874	
57			Industrial	91	91	
58			New Resource	0	0	
59			Intraregional Transfer	80	80	
60			FBS Obligation	673	665	
61			Seasonal or Capacity Exchange	34	31	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	236	237	
64			Slice Return of Losses	35	35	
65			Transmission Losses After Slice Return	201	202	
66						
67		**Annual T1SFCO**		6,973	6,872	
68		**RHWM Process T1SFCO (annual)**		6,989	6,891	
69		**Difference**		(16)	(19)	
70		**Augmentation Price (Secondary in the case Augmentation is zero)**		$ 21.29	$ 29.63	
71		**Hours**		8,784	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ (3,082,374)	$ (4,848,562)	

Table 2.5.5

Rate Design Step
Calculation of Load Shaping and Demand Revenuest
Test Period October 2015 - September 2017

	B	E	F	G	H	I	J	K	L
5	**2016**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
6	Oct-15	335,172	$ 10.02	$ 3,358,420	(178,014)	62,593	$ 27.86	$ 23.75	$ (3,472,883)
7	Nov-15	195,455	$ 10.27	$ 2,007,324	(371,422)	133,683	$ 28.56	$ 24.48	$ (7,335,235)
8	Dec-15	619,669	$ 10.51	$ 6,512,724	129,525	356,520	$ 29.22	$ 24.82	$ 12,633,557
9	Jan-16	504,258	$ 10.79	$ 5,440,946	395,325	616,487	$ 30.02	$ 25.03	$ 27,298,317
10	Feb-16	350,009	$ 10.66	$ 3,731,097	325,301	386,614	$ 29.65	$ 24.68	$ 19,186,832
11	Mar-16	530,868	$ 9.13	$ 4,846,827	5,984	134,601	$ 25.38	$ 22.07	$ 3,122,525
12	Apr-16	424,961	$ 8.76	$ 3,722,654	108,191	180,294	$ 24.36	$ 21.04	$ 6,428,911
13	May-16	261,665	$ 7.95	$ 2,080,238	(1,234,546)	(332,608)	$ 22.10	$ 17.53	$ (33,114,082)
14	Jun-16	377,878	$ 8.33	$ 3,147,724	(596,155)	(178,226)	$ 23.15	$ 17.11	$ (16,850,423)
15	Jul-16	342,157	$ 9.87	$ 3,377,094	(239,573)	280,598	$ 27.43	$ 21.58	$ (516,193)
16	Aug-16	490,169	$ 10.90	$ 5,342,837	(316,622)	122,097	$ 30.30	$ 24.41	$ (6,613,254)
17	Sep-16	383,408	$ 11.42	$ 4,378,521	(21,761)	154,201	$ 31.75	$ 25.70	$ 3,272,049
18	**Total**			**$ 47,946,406**		$ (76,911)			**$ 4,040,119**
19									
20	**2017**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
21	Oct-16	285,874	$ 10.02	$ 2,864,455	(215,558)	110,924	$ 27.86	$ 23.75	$ (3,371,004)
22	Nov-16	265,044	$ 10.27	$ 2,722,000	(300,822)	96,628	$ 28.56	$ 24.48	$ (6,226,007)
23	Dec-16	632,612	$ 10.51	$ 6,648,752	146,349	371,746	$ 29.22	$ 24.82	$ 13,503,053
24	Jan-17	516,843	$ 10.79	$ 5,576,732	419,079	638,757	$ 30.02	$ 25.03	$ 28,568,839
25	Feb-17	324,874	$ 10.66	$ 3,463,160	398,075	438,067	$ 29.65	$ 24.68	$ 22,614,424
26	Mar-17	543,772	$ 9.13	$ 4,964,634	17,183	143,607	$ 25.38	$ 22.07	$ 3,605,526
27	Apr-17	368,143	$ 8.76	$ 3,224,930	66,304	226,717	$ 24.36	$ 21.04	$ 6,385,285
28	May-17	345,184	$ 7.95	$ 2,744,211	(1,207,536)	(376,647)	$ 22.10	$ 17.53	$ (33,289,170)
29	Jun-17	384,980	$ 8.33	$ 3,206,884	(604,204)	(182,119)	$ 23.15	$ 17.11	$ (17,103,369)
30	Jul-17	348,539	$ 9.87	$ 3,440,078	(239,767)	283,752	$ 27.43	$ 21.58	$ (453,441)
31	Aug-17	499,957	$ 10.90	$ 5,449,535	(314,151)	126,014	$ 30.30	$ 24.41	$ (6,442,788)
32	Sep-17	390,295	$ 11.42	$ 4,457,170	(12,719)	162,515	$ 31.75	$ 25.70	$ 3,772,795
33	**Total**			**$ 48,762,542**		$ 192,194			**$ 11,564,144**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B		C		D		E
5	**Costs ($000)**		**2016**		**2017**		**Rate Period**
6	**Composite......**	$	2,690,168	$	2,770,947	$	5,461,115
7	**Non-Slice......**	$	96,182	$	121,330	$	217,513
8	**Slice......**	$	-	$	-	$	-
9	**Tier 2......**	$	22,866	$	27,508	$	50,373
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2016**		**2017**		**Rate Period**
15	DSI Revenue Credit......	**$**	**(33,560)**	**$**	**(33,469)**	**$**	**(67,029)**
16	Exchange Revenues......	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues......	**$**	**(0.64)**	**$**	**(0.65)**	**$**	**(1)**
18	FPS Revenues......	$	(34,537)	$	(34,537)	$	(69,074)
19	Non-Federal RSS Revenues......	$	(1,241)	$	(1,652)	$	(2,894)
20	Other Credits......	$	(253,070)	$	(240,775)	$	(493,845)
21	Tiered Rate Elements......					$	-
22	Unused RHWM Credit Reallocation......	$	(5,991)	$	(2,744)	$	(8,735)
23	Balancing Augmentation Adjustment Reallocation......	$	(1,445)	$	(10,543)	$	(11,988)
24	Composite Augmentation RSS Revenue Debit/(Credit)......	$	(1,725)	$	(1,725)	$	(3,450)
25	Composite Tier 2 RSS Revenue Debit/(Credit)......	$	(83)	$	(91)	$	(174)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)......	$	(725)	$	(835)	$	(1,559)
27	Transmission Losses Adjustment Reallocation......	$	(29,120)	$	(29,437)	$	(58,557)
28	Total......	$	(361,497)	$	(355,808)	$	(717,305)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2016**		**2017**		**Rate Period**
31	Irigation Rate Discout Costs......	$	22,146	$	22,146	$	44,293
32	Low Density Discount Costs......	$	39,865	$	40,464	$	80,329
33	Total......	$	62,012	$	62,610	$	124,622
34							
35			**2016**		**2017**		**Rate Period**
36	**Composite......**	$	2,390,683	$	2,477,749	$	4,868,432

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B	C	D	E
5	**Costs ($000)**	**2016**	**2017**	**Rate Period**
6	**Composite**	$ 2,690,168	$ 2,770,947	$ 5,461,115
7	**Non-Slice**	$ 96,182	$ 121,330	$ 217,513
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 22,866	$ 27,508	$ 50,373
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2016**	**2017**	**Rate Period**
39	Secondary Revenue	$ (339,686)	$ (358,701)	$ (698,387)
40	Unused RHWM Credit Reallocation	$ 5,991	$ 2,744	$ 8,735
41	FPS Revenues not classified as Obligations in TRM	$ (7,850)	$ (3,973)	$ (11,823)
42	Non-federal RSC Revenues	$ 69	$ (26)	$ 43
43	NR Revenues from ESS services	$ (356)	$ (356)	$ (711)
44	Load Shaping Revenue	$ (4,040)	$ (11,564)	$ (15,604)
45	Balancing Augmentation Adjustment Reallocation	$ 1,445	$ 10,543	$ 11,988
46	Demand Revenue	$ (47,946)	$ (48,763)	$ (96,709)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (720)	$ (720)	$ (1,441)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -
49	Non-Slice Tier 2 Rate Design Debit/(Credit)	$ -	$ -	$ -
50	Transmission Losses Adjustment Reallocation	$ 29,120	$ 29,437	$ 58,557
51	Total	$ (363,973)	$ (381,379)	$ (745,352)
52				
53		**2016**	**2017**	**Rate Period**
54	**Non-Slice**	$ (267,791)	$ (260,049)	$ (527,840)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B	C	D	E
5	**Costs ($000)**	**2016**	**2017**	**Rate Period**
6	**Composite.....**	$ 2,690,168	$ 2,770,947	$ 5,461,115
7	**Non-Slice.....**	$ 96,182	$ 121,330	$ 217,513
8	**Slice.....**	$ -	$ -	$ -
9	**Tier 2.....**	$ 22,866	$ 27,508	$ 50,373
55				
56	**TRM Costs after Adjustments**	**2016**	**2017**	**Rate Period**
57	**Composite.....**	$ 2,390,683	$ 2,477,749	$ 4,868,432
58	**Non-Slice.....**	$ (267,791)	$ (260,049)	$ (527,840)
59	**Slice.....**	$ -	$ -	$ -
60	**Tier 2.....**	$ 22,866	$ 27,508	$ 50,373
61	**Total Costs**	$ 2,145,757	$ 2,245,208	$ 4,390,966
62				
63	**Billing Determinants**	**2016**	**2017**	**Rate Period**
64	**TOCA.....**	98.0718	98.6071	98.3394
65	**Non-slice TOCA.....**	71.4531	71.9885	71.7208
66	**Slice Percentage.....**	26.6187	26.6187	26.6187
67				
68	**Annual TRM Rates ($000/percent)**	**2016**	**2017**	**Rate Period**
69	**Composite.....**	$ 24,377	$ 25,127	$ 24,753
70	**Non-Slice.....**	$ (3,748)	$ (3,612)	$ (3,680)
71	**Slice.....**	$ -	$ -	$ -
72				
73	**Monthly TRM Rates ($/percent)**	**2016**	**2017**	**Rate Period**
74	**Composite.....**	2,031,406	2,093,958	2,062,767
75	**Non-Slice.....**	(312,315)	(301,031)	(306,652)
76	**Slice.....**	-	-	-
77				
78	**Tier 2 Rates ($/MWh)**	**2016**	**2017**	**Rate Period**
79	**Tier 2 Short Term.....**	$ 29.72	$ 32.01	$ 30.87
80	**Tier 2 Load Growth.....**	$ 45.18	$ 49.60	$ 47.39
81	**Tier 2 Vintage 2014.....**	$ 44.72	$ 49.08	$ 46.90
82	**Tier 2 Vintage 2016.....**	$ 40.60	$ 43.18	$ 41.89

Table 2.5.7.1

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2015 - September 2017
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2016	2017		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													121,579	1,599	0.017544
14	Federal Base System														
15	Hydro		743,282	757,097		1,500,379	0.0	0.0	0				12.34	0.00	0.00
16	Fish & Wildlife		325,616	336,830		662,447	0.0	0.0	0				5.45	0.00	0.00
17	Trojan		800	800		1,600	0.0	0.0	0				0.01	0.00	0.00
18	WNP #1		259,125	202,867		461,992	0.0	0.0	0				3.80	0.00	0.00
19	WNP #2		363,758	449,939		813,697	0.0	0.0	0				6.69	0.00	0.00
20	WNP #3		225,942	256,332		482,273	0.0	0.0	0				3.97	0.00	0.00
21	System Augmentation		0	20,960		20,960	0.0	0.0	0				0.17	0.00	0.00
22	Balancing Power Purchases		23,342	52,261		75,603	0.0	0.0	0				0.62	0.00	0.00
23	Tier 2 Costs		22,866	27,508		50,373	0.0	0.0	0				0.41	0.00	0.00
24	Total Federal Base System		1,964,731	2,104,595		4,069,325	0.0	0.0	0.0				33.47	0.00	0.00
25															
26	New Resources		69,040	64,435		133,476	0.0	0.0	0		PFx Revenue		1.10	0.00	0.00
27	Residential Exchange		2,825,901	2,829,014		592,608	0.0	0.0	0		5,062,307		4.87	0.00	0.00
28	Conservation		222,404	217,160		439,564	0.0	0.0	0				3.62	0.00	0.00
29	BPA Programs & Transmission		254,162	234,975		489,138	0.0	0.0	0		NR Revenue		4.02	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,336,238	5,450,179		5,724,111	0	0	0		1.3		47.08	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(457,461)	(480,890)		(938,350)	0.0	0.0	0.0				-7.72	0.00	0.00
34	LDD/IRD Expense		62,012	62,610		124,622	0.0						1.03	0.00	0.00
35	Other Revenue Credits		(255,971)	(244,300)		(500,271)	0.0	0.0	0.0				-4.12	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(79,766)	0	0.0	79,766				-0.66	0.00	0.00
38						(1.3)		1.2953					0.00	0.00	73.83
39	IP Rate Revenue		0	0		(67,027)	67,027						-0.55	41.93	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(651,419)	(662,579)		(1,460,793)	67,027	1.3	79,766				-12.02	41.93	73.83
42															
43	Total Generation		4,684,819	4,787,600									**35.07**	**41.93**	**73.83**
44				**PFp Revenue Recovery**		**4,263,317**	67,027	1.3	79,766						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2015 to September 30, 2017

	B	C	D		E		F	G
4								
5								
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**						
7								
8				2016		2017		
9		Composite Revenue..............................	$	2,427,590	$	2,440,841		
10		Non-Slice Revenue...............................	$	(262,935)	$	(264,905)		
11		Slice Revenue...	$	-	$	-		
12		Tier 2...	$	22,866	$	27,508		
13		Load Shaping Revenue..........................	$	4,040	$	11,564		
14		Demand Revenue.................................	$	47,946	$	48,763		
15		Total TRM PF Revenue	$	2,239,508	$	2,263,771		
16								
17		Slice Portion of Secondary Revenue......	$	(117,775)	$	(122,188)		
18		Total Net TRM PF Revenue	$	2,121,733	$	2,141,583		
19								
20							PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF			$	4,263,316	35.07	
22								
23		w/ Slice PF Public Rate Revenue from "Net REP" Table			**$**	**4,263,317**	35.07	
24				delta	$	2		
25								
26								

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75		
16	LLH (mills/kWh)	23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70		
17	Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh)
21	HLH (GWh)	5,552	6,367	7,118	6,625	6,116	6,204	5,353	6,027	5,634	5,895	6,183	5,283		120,286
22	LLH (GWh)	3,517	4,454	4,942	4,861	3,995	4,004	3,532	3,967	3,474	3,911	3,674	3,600		Tier 1 Demand (MW/mo)
23	Demand (MW)	621	460	1,252	1,021	675	1,075	793	607	763	691	990	774		9,722
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 154,665	$ 181,849	$ 207,993	$ 198,852	$ 181,348	$ 157,473	$ 130,379	$ 133,201	$ 130,449	$ 161,695	$ 187,338	$ 167,758		$ 3,086,730
29	LLH ($000)	$ 83,518	$ 109,026	$ 122,657	$ 121,663	$ 98,594	$ 88,367	$ 74,309	$ 69,544	$ 59,442	$ 84,398	$ 89,681	$ 92,532		Demand Revenue ($000)
30	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
31															$ 3,183,439
32															Tier 1 Revenue Requirement (RR) ($000)
33															**$ 4,212,945**
34															Tier 1 RR less Demand Revenue ($000)
35															$ 4,116,236
36	Slice&Non-Slice Tier 1 Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	36.42	37.12	37.78	38.58	38.21	33.94	32.92	30.66	31.71	35.99	38.86	40.31		(8.56)
38	LLH (mills/kWh)	32.31	33.04	33.38	33.59	33.24	30.63	29.60	26.09	25.67	30.14	32.97	34.26		
39	Demand ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 202,186	$ 236,353	$ 268,912	$ 255,573	$ 233,680	$ 210,549	$ 176,210	$ 184,797	$ 178,652	$ 212,178	$ 240,284	$ 212,975		$ 4,116,360
45	LLH ($000)	$ 113,619	$ 147,149	$ 164,959	$ 163,270	$ 132,790	$ 122,641	$ 104,541	$ 103,502	$ 89,181	$ 117,876	$ 121,130	$ 123,351		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
47															$ 4,213,069
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,116,360	34.22												
51	Allocated Cost Demand	$ 96,709	0.80												
52	Total Allocated Costs	$ 4,213,069	35.03												
53															
54		Tier 1 Energy (GWh)	120,286												
55		Market Energy Delta (mills/kWh)	(8.56)												

Table 2.5.8.2

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75		
16	LLH (mills/kWh)	23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70		
17	Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1&2 Energy (GWh)
21	HLH (GWh)	5,614	6,425	7,179	6,683	6,173	6,267	5,413	6,088	5,695	5,954	6,247	5,342		121,579
22	LLH (GWh)	3,564	4,502	4,990	4,911	4,038	4,050	3,578	4,017	3,519	3,962	3,720	3,648		Tier 1 Demand (MW/mo)
23	Demand (MW)	621	460	1,252	1,021	675	1,075	793	607	763	691	990	774		9,722
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 156,403	$ 183,501	$ 209,785	$ 200,621	$ 183,058	$ 159,089	$ 131,841	$ 134,532	$ 131,868	$ 163,311	$ 189,266	$ 169,629		$ 3,119,512
29	LLH ($000)	$ 84,640	$ 110,210	$ 123,856	$ 122,931	$ 99,655	$ 89,379	$ 75,278	$ 70,410	$ 60,209	$ 85,492	$ 90,803	$ 93,743		Demand Revenue ($000)
30	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
31															$ 3,216,221
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,263,319
34															T1&2RR less Demand Revenue ($000)
35															$ 4,166,610
36	PF Melded Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		PF Melded Equivalent Energy Scalar (mills/kWh)
37	HLH (mills/kWh)	36.47	37.17	37.83	38.63	38.26	33.99	32.97	30.71	31.76	36.04	38.91	40.36		(8.61)
38	LLH (mills/kWh)	32.36	33.09	33.43	33.64	33.29	30.68	29.65	26.14	25.72	30.19	33.02	34.31		
39	Demand ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 204,739	$ 238,822	$ 271,587	$ 258,181	$ 236,192	$ 213,022	$ 178,457	$ 186,947	$ 180,880	$ 214,597	$ 243,070	$ 215,618		$ 4,166,284
45	LLH ($000)	$ 115,324	$ 148,973	$ 166,822	$ 165,218	$ 134,421	$ 124,247	$ 106,084	$ 104,992	$ 90,506	$ 119,601	$ 122,832	$ 125,149		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
47															$ 4,262,992
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,166,284	34.27												
51	Allocated Cost Demand	$ 96,709	0.80												
52	Total Allocated Costs	$ 4,262,992	35.06												
53															
54	Tier 1&2 Energy (GWh)		121,579												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(8.61)												

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2015 - September 2017

PF Melded Equiv Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
HLH (mills/kWh)	36.47	37.17	37.83	38.63	38.26	33.99	32.97	30.71	31.76	36.04	38.91	40.36
LLH (mills/kWh)	32.36	33.09	33.43	33.64	33.29	30.68	29.65	26.14	25.72	30.19	33.02	34.31
Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	**Totals** IP Energy (GWh)
HLH (GWh)	78	73	72	75	71	76	76	75	73	74	79	69	1,599
LLH (GWh)	58	59	64	61	53	59	56	60	58	61	57	62	
Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-	

Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	
													Energy Rev & Tier1&2 ($000)
HLH ($000)	$ 2,861	$ 2,707	$ 2,733	$ 2,917	$ 2,721	$ 2,581	$ 2,496	$ 2,311	$ 2,317	$ 2,678	$ 3,064	$ 2,800	$ 54,293
LLH ($000)	$ 1,867	$ 1,946	$ 2,124	$ 2,036	$ 1,779	$ 1,822	$ 1,660	$ 1,569	$ 1,486	$ 1,832	$ 1,873	$ 2,113	Demand Rev ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 54,293

VOR	(0.97)
Industrial Margin (mills/kWh)	0.733
Net industrial Margin	(0.240)
Settlement Charge	**8.204**

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	44.43	45.13	45.79	46.59	46.22	41.95	40.93	38.67	39.72	44.00	46.87	48.32
LLH (mills/kWh)	40.32	41.05	41.39	41.60	41.25	38.64	37.61	34.10	33.68	38.15	40.98	42.27
Demand ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	
													Allocated Cost Energy ($000)
HLH ($000)	$ 3,486	$ 3,287	$ 3,308	$ 3,517	$ 3,287	$ 3,186	$ 3,099	$ 2,910	$ 2,897	$ 3,270	$ 3,690	$ 3,353	$ 67,018
LLH ($000)	$ 2,326	$ 2,414	$ 2,629	$ 2,517	$ 2,204	$ 2,295	$ 2,106	$ 2,047	$ 1,946	$ 2,315	$ 2,325	$ 2,603	Allocated Cost Demand ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 67,018

Average IP Rate	($000)	(mills/kWh)
Allocated Cost Energy	$ 67,018	41.92
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 67,018	41.92
IP Energy (GWh)		1,599
Industrial Margin (mills/kWh)		0.73
VOR		(0.97)
Settlement Charge		8.20

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75		
16	LLH (mills/kWh)	23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70		
17	Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0008	0.0008	0.0008	0.0008	0.0008	0.0009	0.0008	0.0008	0.0008	0.0008	0.0009	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0007	0.0006	0.0007	0.0006	0.0006		Demand (MW/mo)
23	Demand (MW)														-
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 0.0236	$ 0.0224	$ 0.0243	$ 0.0240	$ 0.0232	$ 0.0219	$ 0.0199	$ 0.0180	$ 0.0193	$ 0.0219	$ 0.0262	$ 0.0254		$ 0.4450
29	LLH ($000)	$ 0.0152	$ 0.0161	$ 0.0163	$ 0.0172	$ 0.0144	$ 0.0137	$ 0.0131	$ 0.0118	$ 0.0104	$ 0.0148	$ 0.0152	$ 0.0164		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.4450
32															NR Revenue Requirement (RR) ($000)
33															$ 1.2953
34															NR RR less Demand Revenue ($000)
35															$ 1.2953
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	76.33	77.03	77.69	78.49	78.12	73.85	72.83	70.57	71.62	75.90	78.77	80.22		(48.47)
38	LLH (mills/kWh)	72.22	72.95	73.29	73.50	73.15	70.54	69.51	66.00	65.58	70.05	72.88	74.17		
39	Demand ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
40															
41															
42															
43	evenues @ Posted NR Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 0.0647	$ 0.0604	$ 0.0646	$ 0.0628	$ 0.0612	$ 0.0638	$ 0.0594	$ 0.0576	$ 0.0596	$ 0.0607	$ 0.0681	$ 0.0642		$ 1.2954
45	LLH ($000)	$ 0.0462	$ 0.0480	$ 0.0481	$ 0.0506	$ 0.0427	$ 0.0439	$ 0.0434	$ 0.0444	$ 0.0399	$ 0.0482	$ 0.0455	$ 0.0475		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.2954
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.2954	73.84												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.2954	73.84												
53															
54		NR Energy (GWh)	0.0175												
55															

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	27.86	28.56	29.22	30.02	29.65	25.38	24.36	22.10	23.15	27.43	30.30	31.75		
16	LLH (mills/kWh)	23.75	24.48	24.82	25.03	24.68	22.07	21.04	17.53	17.11	21.58	24.41	25.70		
17	Demand Rate ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	3,958	4,458	5,227	5,101	4,575	4,562	3,948	3,734	3,781	4,154	4,325	3,835		87,981
22	LLH (GWh) [FMDT1L]	2,652	3,333	3,796	3,927	3,138	3,041	2,712	2,721	2,459	3,044	2,767	2,733		Tier 1 Demand (MW/mo)
23	Demand (MW)	621	460	1,252	1,021	675	1,075	793	607	763	691	990	774		9,722
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000) [MktR]
28	HLH ($000)	$ 110,257	$ 127,332	$ 152,743	$ 153,123	$ 135,650	$ 115,800	$ 96,169	$ 82,530	$ 87,547	$ 113,931	$ 131,042	$ 121,773		$ 2,259,827
29	LLH ($000)	$ 62,994	$ 81,591	$ 94,208	$ 98,284	$ 77,436	$ 67,118	$ 57,056	$ 47,698	$ 42,077	$ 65,682	$ 67,555	$ 70,231		Demand Revenue ($000)
30	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
31															$ 2,356,536
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															**$ 3,135,166**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 3,038,457
36	Non-Slice Tier 1 PF Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Load Shaping True-up Rate (mills/kWh) [LSTUR]
37	HLH (mills/kWh)	36.71	37.41	38.07	38.87	38.50	34.23	33.21	30.95	32.00	36.28	39.15	40.60		(8.85)
38	LLH (mills/kWh)	32.60	33.33	33.67	33.88	33.53	30.92	29.89	26.38	25.96	30.43	33.26	34.55		
39	Demand ($/kW/mo)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 145,281	$ 166,790	$ 198,996	$ 198,280	$ 176,121	$ 156,152	$ 131,120	$ 115,582	$ 120,993	$ 150,707	$ 169,333	$ 155,708		$ 3,038,442
45	LLH ($000)	$ 86,467	$ 111,088	$ 127,800	$ 133,034	$ 105,204	$ 94,032	$ 81,056	$ 71,778	$ 63,841	$ 92,618	$ 92,047	$ 94,416		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,223	$ 4,729	$ 13,161	$ 11,018	$ 7,194	$ 9,811	$ 6,948	$ 4,824	$ 6,355	$ 6,817	$ 10,792	$ 8,836		$ 96,709
47															$ 3,135,151
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,038,442	34.54												
51	Allocated Cost Demand	$ 96,709	1.10												
52	Total Allocated Costs	$ 3,135,151	35.63												
53															
54	Tier 1 Energy (GWh) [FAT1L]		87,981												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(8.85)												

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L
11											
12			**A**	**B**	**C**		**PF Public**		**PF Exchange**		
13			**ALLOCATED**	**UNIT**	**PERCENT**		**ALLOCATED**		**ALLOCATED**		
14			**COSTS**	**COSTS**	**CONTRIBUTION**		**COSTS**		**COSTS**		
15		GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)						
16											
17		Federal Base System									
18		Hydro	1,500,379	6.975	16.09%		848,040	6.975	652,340	6.975	
19		Fish & Wildlife	662,447	3.080	7.10%		374,426	3.080	288,021	3.080	
20		Trojan	1,600	0.007	0.02%		904	0.007	696	0.007	
21		WNP #1	461,992	2.148	4.95%		261,125	2.148	200,866	2.148	
22		WNP #2	813,697	3.783	8.73%		459,915	3.783	353,782	3.783	
23		WNP #3	482,273	2.242	5.17%		272,589	2.242	209,684	2.242	
24		System Augmentation	20,960	0.097	0.22%		11,847	0.097	9,113	0.097	
25		Balancing Power Purchases	75,603	0.351	0.81%		42,732	0.351	32,871	0.351	
26		Tier 2 Costs	50,373	0.234	0.54%		28,472	0.234	21,902	0.234	
27		Total Federal Base System	4,069,325	18.918	43.64%		2,300,051	18.918	1,769,275	18.918	
28		New Resources									
29		Gross Residential Exchange	5,536,090	25.737	59.37%		3,129,091	25.737	2,406,999	25.737	
30		Conservation	431,894	2.008	4.63%		244,114	2.008	187,780	2.008	
31		BPA Programs	104,395	0.485	1.12%		59,006	0.485	45,389	0.485	
32		Power Transmission	376,179	1.749	4.03%		212,623	1.749	163,556	1.749	
33		TOTAL COSA ALLOCATIONS	10,517,883	48.897	112.79%		5,944,884	48.897	4,573,000	48.897	
34											
35											
36		Nonfirm Excess Revenue Credit	(924,530)	-4.298	-9.91%		(522,560)	-4.298	(401,970)	-4.298	
37		Low Density Discount Expense	124,622	0.579	1.34%		70,439	0.579	54,184	0.579	
38		Other Revenue Credits	(493,776)	-2.296	-5.29%		(279,090)	-2.296	(214,686)	-2.296	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	63,821	0.297	0.68%		36,072	0.297	27,748	0.297	
41		7(c)(2) Delta Adjustment	37,471	0.174	0.40%		21,179	0.174	16,292	0.174	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,192,393)	-5.543	-12.79%		(673,960)	-5.543	(518,432)	-5.543	
44											
45		Total Generation	9,325,491	**43.3539**	100.00%		5,270,923	**43.35**	4,054,567	**43.35**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,020,718)	-8.396	1,007,774	1,007,774	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					13,080	0.108	1	0.000	
50		Total Generation					**4,263,285**	**35.07**	5,062,341	**54.13**	
51											
52		Total Transmission							430,203	4.600	
53									5,492,545	**58.73**	
54											

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2015 - September 2017

	C	D	E	F
13		**ALLOCATED**	**UNIT**	**PERCENT**
14		**COSTS**	**COSTS**	**CONTRIBUTION**
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
16				
17	Federal Base System			
18	Hydro			
19	Fish & Wildlife			
20	Trojan			
21	WNP #1			
22	WNP #2			
23	WNP #3			
24	System Augmentation			
25	Balancing Power Purchases			
26	Total Federal Base System			
27	New Resources	56,594	35.402	84.43%
28	Gross Residential Exchange	49,349	30.870	73.62%
29	Conservation	3,210	2.008	4.79%
30	BPA Programs	776	0.486	1.16%
31	Power Transmission	2,795	1.749	4.17%
32	TOTAL COSA ALLOCATIONS	112,725	70.515	168.17%
33				
34	Nonfirm Excess Revenue Credit	(5,867)	-3.670	-8.75%
35				
36	Other Revenue Credits	(2,701)	-1.689	-4.03%
37				
38	SP Revenue Surplus/Dfct Adj.	475	0.297	0.71%
39	7(c)(2) Delta Adjustment	(37,471)	-23.440	-55.90%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(45,564)	-28.502	-67.98%
42	Total Generation	67,161	42.013	100.20%
43				
55	Total Allocated & Adjusted Costs	67,161	42.013	100.20%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	12,945	8.097	19.31%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(13,080)	-8.182	-19.51%
60		67,026	**41.93**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	1,599		

Table 2.5.9.3

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2015 - September 2017

	C	D	E	F
12		**ALLOCATED**	**UNIT**	**PERCENT**
13		**COSTS**	**COSTS**	**CONTRIBUTION**
14	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
15				
16	Federal Base System			
17	Hydro			
18	Fish & Wildlife			
19	Trojan			
20	WNP #1			
21	WNP #2			
22	WNP #3			
23	System Augmentation			
24	Balancing Power Purchases			
25	Total Federal Base System			
26	New Resources	0.6211	35.402	47.95%
27	Gross Residential Exchange	0.5416	30.870	41.81%
28	Conservation	0.0352	2.008	2.72%
29	BPA Programs	0.0392	2.234	3.03%
30	TOTAL COSA ALLOCATIONS	1.2371	70.515	95.51%
31				
32	Nonfirm Excess Revenue Credit	(0.0644)	-3.670	-4.97%
33				
34	Other Revenue Credits	(0.0296)	-1.689	-2.29%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0052	0.297	0.40%
37	7(c)(2) Delta Adjustment	0.0031	0.174	0.24%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0858)	-4.888	-6.62%
40	Total Generation Energy	1.1514	65.627	88.89%
41				
50				
51	Total Allocated & Adjusted Costs	1.1514	65.627	88.89%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1421	8.097	10.97%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0019	0.108	0.15%
55				
56	Total With 7(b)(2) Adjustments	1.2953	**73.83**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01754		

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K
9		**ALLOCATED GENERATION COSTS**					**PERCENTAGES**			
10										
11		**FBS**	**Exchange**	**New**			**FBS**	**Exchange**	**New**	
12		**Resources**	**Resources**	**Resources**	**Total**		**Resources**	**Resources**	**Resources**	**Total**
13										
14	**CLASSES OF SERVICE:**									
15										
16	**Power Rates**									
17	Priority Firm - Public	2,300,051	3,129,091		5,429,142		42.36%	57.64%		100.00%
18	Priority Firm - Exchange	1,769,275	2,406,999		4,176,274		42.36%	57.64%		100.00%
19	Priority Firm Power - Total	4,069,325	5,536,090		9,605,415		42.36%	57.64%		100.00%
20	Industrial Firm Power		49,349	56,594	105,943			46.58%	53.42%	100.00%
21	New Resources Firm		0.542	1	1			46.58%	53.42%	100.00%
22	Firm Power Products and Services		69,476	76,881	146,357			47.47%	52.53%	100.00%
23										
24										
25	**TOTALS**	**4,069,325**	**5,654,915**	**133,476**	**9,857,716**		**41.28%**	**57.37%**	**1.35%**	**100.00%**
26										
27					216,700					
28										
29				Average Cost of Resources	45.49					
30										
31				Average Cost to Serve Load Growth	43.09					

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SECTION 3: RATE DESIGN

Table Descriptions

Table 3.1
Summary RSS Revenue Credits for Tier 1 Cost Pools
Table summarizes the total revenue credits associated with RSS and related services, delineated by Tier 1 cost pool.

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Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

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Load Shaping Rates
Table shows calculation of the PF Load Shaping rates, NR Load Shaping Rates, and the flat annual block AURORA market price forecast.

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Tier 1 Demand Rates
Table shows calculation of the Tier 1 Demand rate.

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Slice Billing Adjustment
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Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

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Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit.

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Inputs to TSS Monthly Rate and Charge
Table shows costs used as the numerator and the megawatt hours sold as the denominator for the TSS rate. The transaction values are used to calculate the charge cap.

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Tier 2 Short-Term Rate Costing Table
Costing table used to calculate the Tier 2 Short-Term rates for each year of the rate period.

Table 3.10
Tier 2 Load Growth Rate Costing Table
Costing table used to calculate the Tier 2 Load Growth rates for each year of the rate period.

Table 3.11
Tier 2 VR1-2014 Rate Costing Table
Costing table used to calculate the VR1-2014 rates for each year of the rate period.

Table 3.12
Tier 2 VR1-2016 Rate Costing Table
Costing table used to calculate the VR1-2016 rates for each year of the rate period.

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Tier 2 Purchases Made by BPA
Table lists information pertaining to Mid-C purchases made by BPA to meet Tier 2 rate load obligations.

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Table summarizes the sources of power for meeting different Tier 2 loads including purchases, executed and forecast, remarketed power from other Tier 2 cost pools, and remarketed power from non-Federal resources with DFS.

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Tier 2 Load Obligations
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Customers Receiving a VR1-2014 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2014 purchases and their associated credits.

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Customers Receiving a VR1-2016 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2016 purchases and their associated credits.

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Customers Receiving a FY16 Load Growth Customer Charge
List of Load Growth rate customers and their customer charges.

Table 3.19
Customers Receiving a FY17 Load Growth Customer Charge
List of Load Growth rate customers and their customer charges.

Table 3.20
Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' contract CHWM.

Table 3.21
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017
Table summarizes the RSS model forecast results for the purchaser's grandfathered GMS, SCS, DFS, FORS and TSS/TCMS. This table also shows who is taking what service, during which year, and for what resource. Table summarizes the revenue credits by customers produced by the RSS model when applying

the RSS and related services' charges to the identified resources. Also included is the all-in forecast $/MW equivalent rate for the identified services.

Table 3.22
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS
List of customers with remarketed Non-Federal resources with DFS and their associated credits.

Table 3.23
WECC and Peak Dues Charge Calculation
Table shows calculations for the WECC Dues Charge and the Peak Dues Charge.

Table 3.24
Southeast Idaho Load Service Five-Year Market Purchases
Table shows calculations for the Southeast Idaho Load service five-year market purchases.

Table 3.25
Southeast Idaho Load Service Market Purchases - Monthly Power Purchase Segmented by Cost Pool and by Fiscal Year
Table shows the monthly transfer cost by fiscal year for the Southeast Idaho Load service five-year market purchases.

Table 3.1
Summary RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G	H	I	J
1	**TRM**	**COSA**	**Aggregation Key**	**Category**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$2,445	$2,445	$2,445	$2,445	$2,445	$2,445
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	($1,725)	($1,725)	($1,725)	($1,725)	($1,725)	($1,725)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$0	$0	$0	$0	$0	$0
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	($1,241)	($1,652)	($1,652)	($1,652)	($1,652)	($1,652)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	($720)	($720)	($720)	($720)	($720)	($720)
7	2.0	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$0	$0	$0	$0	$0	$0
8	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	$69	($26)	($26)	($26)	($26)	($26)

Data shown in $ thousands

Table 3.2
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		**BP-16**			
2		**FY2016**		**FY2017**	
3	**Line Item**	**FY2016**	**Total Forecast Sales (MWh)**	**FY2017**	**Total Forecast Sales (MWh)**
4	Executive and Administrative Services	$ 4,316,887	77,959,040	$ 4,392,446	77,659,526
5	Generation Project Coordination	$ 7,735,034		$ 7,844,803	
6	Sales & Support	$ 22,139,341		$ 24,854,473	
7	Strategy, Finance & Risk Mgmt.	$ 21,628,064		$ 21,540,824	
8	Agency Services G&A	$ 42,731,406		$ 44,344,577	

Table 3.3
Load Shaping Rates

	A	B	C	D	E	F	G
1		**Aurora Market Prices**				**Load Shaping Rates**	
2		HLH - $/MWh	LLH - $/MWh			HLH - $/MWh	LLH - $/MWh
3	Oct-15	25.98	22.20		October	27.86	23.75
4	Nov-15	27.04	23.31		November	28.56	24.48
5	Dec-15	27.68	23.59		December	29.22	24.82
6	Jan-16	28.31	23.44		January	30.02	25.03
7	Feb-16	27.74	23.19		February	29.65	24.68
8	Mar-16	24.22	21.11		March	25.38	22.07
9	Apr-16	23.63	20.28		April	24.36	21.04
10	May-16	21.31	16.84		May	22.10	17.53
11	Jun-16	22.13	16.09		June	23.15	17.11
12	Jul-16	26.87	21.14		July	27.43	21.58
13	Aug-16	29.77	24.06		August	30.30	24.41
14	Sep-16	31.19	25.35		September	31.75	25.70
15	Oct-16	29.74	25.30				
16	Nov-16	30.08	25.64				$/MWh
17	Dec-16	30.76	26.05	FY2014 Aurora Flat Annual Block			24.29
18	Jan-17	31.73	26.62	FY2015 Aurora Flat Annual Block			26.43
19	Feb-17	31.57	26.18				
20	Mar-17	26.54	23.03				
21	Apr-17	25.09	21.79				
22	May-17	22.89	18.22				
23	Jun-17	24.18	18.14				
24	Jul-17	27.98	22.02				
25	Aug-17	30.82	24.77				
26	Sep-17	32.31	26.05				

Table 3.4
Tier 1 Demand Rates

	A	B	C	D	E	F	G	H	I	J
1				Calendar Year	Chained GDP IPD		Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
2	Start Year of Operation (FY)	2016		2009	100.00		Oct	27.86	8.45%	$ 10.02
3	Cost of Debt	4.71%	/1	2010	101.22		Nov	28.56	8.66%	$ 10.27
4				2011	103.31		Dec	29.22	8.86%	$ 10.51
5	Inflation Rate	1.61%		2012	105.17		Jan	30.02	9.10%	$ 10.79
6	Insurance Rate	0.25%	/2	2013	106.73		Feb	29.65	8.99%	$ 10.66
7				2014	108.29		Mar	25.38	7.70%	$ 9.13
8	Debt Finance Period (years)	30	/2				Apr	24.36	7.39%	$ 8.76
9	Plant Lifecycle (years)	30	/2		101.61%	5-year Ave.	May	22.10	6.70%	$ 7.95
10							Jun	23.15	7.02%	$ 8.33
11	Plant in service 2016 Vintaged Heat Rate Btu/kWh	8,541	/2	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2009 Base year)- Last Revised June 25, 2014			Jul	27.43	8.32%	$ 9.87
12							Aug	30.30	9.19%	$ 10.90
13	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2				Sep	31.75	9.63%	$ 11.42
14	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 46.97	/2					Average $/kW/mo		$ 9.88
15	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 39.52								
16	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 55.08								
17	Average of Existing and New with 10000 Heat Rate 2014$	$ 47.30								
18	Average of Existing and New with 8541 Heat Rate 2014$	$ 40.40								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,011.00	/2	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21	Fixed O&M $/kW/yr 2016$	$ 11.72	/3	2016	$ 994.15	$63.61	$ 11.72	$ 2.49	$ 40.40	$ 118.21
22	Fixed Fuel $/kW/yr	$ 40.40		2017	$ 960.45	$63.61	$ 11.91	$ 2.40	$ 41.05	$ 118.97
23						Rate Period Average Expense $/kW/year				$ 118.59
24	/1 Source BPA FY 2015 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
25	/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.71% with plant in service 2016 and PNWE fixed fuel. Version 15.0.1									
26	/3 Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$									

Table 3.5
Slice Billing Adjustment

	A	B	C	D	E	F	G	H	I	J
1			BP-12	FY2012	FY2013		BP-14	FY2014	FY2015	
2		WNP3/PGE Adjustment		$ 3,524,000	$ 3,524,000			$ 3,524,000	$ 3,524,000	
3		Sum of TOCA		0.9605186	0.964213			0.9797477	0.9851395	
4		Adjusted Amount		$ 3,668,851	$ 3,654,794			$ 3,596,844	$ 3,577,158	
5		Total Slice %	26.854070%	$ 985,236	$ 981,461		26.627520%	$ 957,750	$ 952,509	
6										
7		SLICE PERCENTAGES		Charge	Charge			Charge	Charge	Total Charge
8	Cust ID	Customer Name	Slice %	Amount	Amount		Slice %	Amount	Amount	Amount
9		Subtotal	26.85407%	$ 985,235	$ 981,460		26.62752%	$ 957,750	$ 952,508	$ 3,876,953
10	10024	BENTON PUD	1.37242%	$ 50,352	$ 50,159		1.37031%	$ 49,288	$ 49,018	$ 198,817
11	10103	CLARK PUD	2.18934%	$ 80,324	$ 80,016		2.18597%	$ 78,626	$ 78,196	$ 317,162
12	10105	CLATSKANIE PUD	0.72773%	$ 26,699	$ 26,597		0.72661%	$ 26,135	$ 25,992	$ 105,423
13	10123	COWLITZ	4.00153%	$ 146,810	$ 146,248		3.99536%	$ 143,707	$ 142,920	$ 579,685
14	10157	EMERALD	0.37102%	$ 13,612	$ 13,560		0.37045%	$ 13,325	$ 13,252	$ 53,749
15	10170	EWEB	1.79926%	$ 66,012	$ 65,759		1.79649%	$ 64,617	$ 64,263	$ 260,651
16	10183	FRANKLIN PUD	0.78152%	$ 28,673	$ 28,563		0.78031%	$ 28,067	$ 27,913	$ 113,216
17	10191	GRAYS HARBOR PUD	0.97145%	$ 35,641	$ 35,504		0.96996%	$ 34,888	$ 34,697	$ 140,730
18	10204	IDAHO FALLS	0.55073%	$ 20,205	$ 20,128		0.54988%	$ 19,778	$ 19,670	$ 79,781
19	10231	KLICKITAT PUD	0.23690%	$ 8,692	$ 8,658		0.23654%	$ 8,508	$ 8,461	$ 34,319
20	10237	LEWIS PUD	0.96364%	$ 35,355	$ 35,219		0.96216%	$ 34,607	$ 34,418	$ 139,599
21	10286	OKANOGAN PUD	0.36217%	$ 13,287	$ 13,237		0.36161%	$ 13,007	$ 12,935	$ 52,466
22	10294	PACIFIC PUD	0.28252%	$ 10,365	$ 10,326		0.28209%	$ 10,146	$ 10,091	$ 40,928
23	10306	PEND OREILLE PUD	0.18549%	$ 6,805	$ 6,779		0.00000%	$ -	$ -	$ 13,584
24	10349	SEATTLE	3.63323%	$ 133,298	$ 132,787		3.62763%	$ 130,480	$ 129,766	$ 526,331
25	10354	SNOHOMISH PUD	5.45427%	$ 200,109	$ 199,342		5.44587%	$ 195,879	$ 194,807	$ 790,137
26	10370	TACOMA	2.97085%	$ 108,996	$ 108,578		2.96628%	$ 106,692	$ 106,109	$ 430,375
27										$ 3,876,953

Table 3.6
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 29.72	$ 32.01
5	LoadGrowth Rate $/MWh	$ 45.18	$ 49.60
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 44.72	$ 49.08
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 40.60	$ 43.18
8			
9	**ShortTerm**		
10	Portfolio Purchased aMW	0.000	0.000
11	Portfolio Purchased MWh	0	0
12	Portfolio Obligation /w Losses aMW	9.506	8.986
13	Portfolio Obligation /w Losses MWh	83,504	78,716
14	Portfolio Billing Determinant aMW	9.224	8.719
15	Portfolio Billing Determinant MWh	81,024	76,378
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ -	$ -
18	Rate Design Components	$ 114,165	$ 112,346
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 29.72	$ 32.01
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (102,425)	$ (101,278)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,740)	$ (11,067)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total ShortTerm Rate Revenue	$ 2,408,022	$ 2,444,874
27	Remarketing Credit	$ -	$ -
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ -	$ -
30			
31	**LoadGrowth**		
32	Portfolio Purchased aMW	5.000	5.000
33	Portfolio Purchased MWh	43,920	43,800
34	Portfolio Obligation /w Losses aMW	1.080	1.152
35	Portfolio Obligation /w Losses MWh	9,487	10,093
36	Portfolio Billing Determinant aMW	1.048	1.118
37	Portfolio Billing Determinant MWh	9,206	9,794
38	RECs MWh	0	0
39	Base Power Purchase Cost	$ 1,865,282	$ 2,045,460
40	Rate Design Components	$ 12,971	$ 14,406
41	Other Costs	$ -	$ -
42	Rate $/MWh	$ 45.18	$ 49.60
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (11,637)	$ (12,986)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,334)	$ (1,419)
46	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48	Total LoadGrowth Rate Revenue	$ 415,910	$ 485,767
49	Remarketing Credit	$ -	$ -
50	Remarketing Charge	$ 516,489	$ 575,371
51	Forecast Power Purchase Costs	$ -	$ -

Table 3.6 (continued)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 29.72	$ 32.01
5	LoadGrowth Rate $/MWh	$ 45.18	$ 49.60
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 44.72	$ 49.08
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 40.60	$ 43.18
8			
9	**Vintage.1 (VR1-2014)**		
10	Portfolio Purchased aMW	46.000	46.000
11	Portfolio Purchased MWh	404,064	402,960
12	Portfolio Obligation /w Losses aMW	47.408	47.408
13	Portfolio Obligation /w Losses MWh	416,432	415,294
14	Portfolio Billing Determinant aMW	46.000	46.000
15	Portfolio Billing Determinant MWh	404,064	402,960
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ 17,160,598	$ 18,818,232
18	Rate Design Components	$ 569,340	$ 592,717
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 44.72	$ 49.08
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,791)	$ (534,328)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (58,549)	$ (58,389)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total Vintage.1 Rate Revenue	$ 18,069,742	$ 19,777,277
27	Remarketing Credit	$ 1,909,138	$ 2,145,775
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ -	$ -
30			
31	**Vintage.2 (VR1-2016)**		
32	Portfolio Purchased aMW	9.000	16.000
33	Portfolio Purchased MWh	79,056	140,160
34	Portfolio Obligation /w Losses aMW	9.275	16.490
35	Portfolio Obligation /w Losses MWh	81,476	144,450
36	Portfolio Billing Determinant aMW	9.000	16.000
37	Portfolio Billing Determinant MWh	79,056	140,160
38	RECs MWh	0	0
39	Base Power Purchase Cost	$ 3,031,798	$ 5,718,528
40	Rate Design Components	$ 111,393	$ 206,162
41	Other Costs	$ -	$ -
42	Rate $/MWh	$ 40.60	$ 43.18
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (99,937)	$ (185,853)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,455)	$ (20,309)
46	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48	Total Vintage.2 Rate Revenue	$ 3,209,674	$ 6,052,109
49	Remarketing Credit	$ 965,186	$ 1,330,772
50	Remarketing Charge	$ -	$ -
51	Forecast Power Purchase Costs	$ -	$ -

Table 3.6 (continued) (2)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 29.72	$ 32.01
5	LoadGrowth Rate $/MWh	$ 45.18	$ 49.60
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 44.72	$ 49.08
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 40.60	$ 43.18
8			
9	**Total Costs**		
10	Total Base Power Purchase Cost	$ 22,057,678	$ 26,582,220
11	Total Rate Design Components	$ 807,869	$ 925,631
12	Total Other Costs	$ -	$ -
13	Forecast Power Purchase Costs	$ -	$ -
14	Total Cost	$ 22,865,547	$ 27,507,851
15			
16	**Total Revenue**		
17	Total Tier 2 Rate Revenue Collection	$ 24,103,348	$ 28,760,026
18	Total Tier 2 Remarketing Charge	$ 516,489	$ 575,371
19	Total Tier 2 Remarketing Credit	$ (2,874,323)	$ (3,476,547)
20	Non-Federal Remarketing Credit	$ (1,119,622)	$ (650,704)
21	Total Revenue	$ 20,625,891	$ 25,208,145
22	Value of BPA Purchased Remarketing	$ 2,239,740	$ 2,301,031
23	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 22,865,632	$ 27,509,176
24			
25	Total Tier 2 Adjustments and Credits*		
26	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (724,791)	$ (834,446)
27	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
28	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (83,078)	$ (91,184)
29	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
30	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
31			
32	*This amount is in addition to any RSS credits that result from the RSS model		

Table 3.7
Tier 2 Rate Inputs

	A	B	C	D	E	F	G	H	I
1	**Fiscal Year**	**TSS Rate ($/MWh)**	**Aurora Flat Annual Block Market Forecast ($/MWh)**	**Augmentation Price ($/MWh)**	**Augmentation Amount (MWh)**	**Remarketing Value ($/MWh)**	**Available Non-Federal Resource Remarketing (MWh)**	**Vintage.1 (VR1-2014) Remarketing (MWh)**	**Vintage.2 (VR1-2016) Remarketing (MWh)**
2	FY2016	$ 0.14	$ 24.29	$ 27.47	-	$ 27.47	40,758	69,499	35,136
3	FY2017	$ 0.14	$ 26.43	$ 29.63	709,560	$ 29.63	21,961	72,419	44,913

Table 3.8
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	**PTK Costs FY2016**	**PTK Costs FY2017**	**FY2013 Scheduled (MWh)**	**FY2014 Scheduled (MWh)**	**FY2013 Transactions**	**FY2014 Transactions**
2	$3,969,935	$4,075,903	28,201,197	27,309,297	122,273	124,563

Table 3.9
Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.2.2015_2019	ST.2.2015_2019
2	Hours	8784	8760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 2,408,011	$ 2,444,710
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ -
7	Power Purchase Cost	$ -	$ -
8	Transmission	$ -	$ -
9	Third Party PTP		
10	Ancillary Services		
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses		
15	Rate Design Components (Provided by PFR & PTM)	$ 114,165	$ 112,346
16	Resource Support Services	$ 11,740	$ 11,067
17	Diurnal Flattening Service	$ -	$ -
18	DFS Energy (Variable)		
19	DFS Capacity (Fixed)		
20	Forced Outage Reserve	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)		
22	Transmission Scheduling Services	$ 11,740	$ 11,067
23	Transmission Curtailment Management Service Capacity (Fixed)		
24	Transmission Curtailment Management Service Energy (Variable)		
25	Alternative Transmission Path Costs		
26	Generation Imbalance		
27	TSS - Overhead	$ 11,740	$ 11,067
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 102,425	$ 101,278
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	0	0
34	Tier 2 Obligation w/o losses (Billing Determinant)	81,024	76,378
35	Tier 2 Obligation w losses	83,504	78,716
36	Energy (Short)/Long (MWh)	-83,504	-78,716
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-83,504	-78,716
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,826	173,000
41	Total Tier 2 Pool Shortfall (MWh)	-98,292	-95,341
42	Augmentation Price ($/MWh)	$ 27.47	$ 29.63
43	Flat Block RSC ($/MWh)	$ 24.29	$ 26.43
44	Remarketing Value ($/MWh)	$ 27.47	$ 29.63
45	Remarketed Purchase (MWh)	83,504	78,716
46	Remarketed Purchase Cost	$ 2,293,846	$ 2,332,364
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)		
52	Total Fixed Costs	$ 2,408,011	$ 2,444,710
53	Billing Components		
54	ShortTerm ($/MWh)	$ 29.72	$ 32.01
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (102,425)	$ (101,278)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,740)	$ (11,067)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.10
Tier 2 Load Growth Rate Costing Table

	A	B	C
1		LG.1.2012_2028	LG.1.2012_2028
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 1,878,253	$ 2,059,866
6	Base Power Purchase Cost (Provided by PTL)	$ 1,865,282	$ 2,045,460
7	Power Purchase Cost	$ 1,865,282	$ 2,045,460
8	Transmission	$ -	$ -
9	Third Party PTP		
10	Ancillary Services		
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses		
15	Rate Design Components (Provided by PFR & PTM)	$ 12,971	$ 14,406
16	Resource Support Services	$ 1,334	$ 1,419
17	Diurnal Flattening Service	$ -	$ -
18	DFS Energy (Variable)		
19	DFS Capacity (Fixed)		
20	Forced Outage Reserve	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)		
22	Transmission Scheduling Services	$ 1,334	$ 1,419
23	Transmission Curtailment Management Service Capacity (Fixed)		
24	Transmission Curtailment Management Service Energy (Variable)		
25	Alternative Transmission Path Costs		
26	Generation Imbalance		
27	TSS - Overhead	$ 1,334	$ 1,419
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 11,637	$ 12,986
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	43,920	43,800
34	Tier 2 Obligation w/o losses (Billing Determinant)	9,206	9,794
35	Tier 2 Obligation w losses	9,487	10,093
36	Energy (Short)/Long (MWh)	34,433	33,707
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	0	0
39	Energy to be Remarketed (MWh)	34,433	33,707
40	Remarketing Available (MWh)	179,826	173,000
41	Total Tier 2 Pool Shortfall (MWh)	-98,292	-95,341
42	Augmentation Price ($/MWh)	$ 27.47	$ 29.63
43	Flat Block RSC ($/MWh)	$ 24.29	$ 26.43
44	Remarketing Value ($/MWh)	$ 27.47	$ 29.63
45	Remarketed Purchase (MWh)	0	0
46	Remarketed Purchase Cost	0	0
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	Yes	Yes
51	Additional Remarketing - Vintage Only (MWh)		
52	Total Fixed Costs	$ 1,878,253	$ 2,059,866
53	Billing Components		
54	LoadGrowth ($/MWh)	$ 45.18	$ 49.60
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ 516,489	$ 575,371
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (11,637)	$ (12,986)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,334)	$ (1,419)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.11
Tier 2 VR1-2014 Rate Costing Table

	A	B	C
1		V.1.2014_2018	V.1.2014_2018
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 18,069,688	$ 19,776,412
6	Base Power Purchase Cost (Provided by PTL)	$ 17,160,598	$ 18,818,232
7	Power Purchase Cost	$ 17,160,598	$ 18,818,232
8	Transmission	$ -	$ -
9	Third Party PTP		
10	Ancillary Services		
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses		
15	Rate Design Components (Provided by PFR & PTM)	$ 569,340	$ 592,717
16	Resource Support Services	$ 58,549	$ 58,389
17	Diurnal Flattening Service	$ -	$ -
18	DFS Energy (Variable)		
19	DFS Capacity (Fixed)		
20	Forced Outage Reserve	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)		
22	Transmission Scheduling Services	$ 58,549	$ 58,389
23	Transmission Curtailment Management Service Capacity (Fixed)		
24	Transmission Curtailment Management Service Energy (Variable)		
25	Alternative Transmission Path Costs		
26	Generation Imbalance		
27	TSS - Overhead	$ 58,549	$ 58,389
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 510,791	$ 534,328
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	404,064	402,960
34	Tier 2 Obligation w/o losses (Billing Determinant)	404,064	402,960
35	Tier 2 Obligation w losses	416,432	415,294
36	Energy (Short)/Long (MWh)	-12,368	-12,334
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-12,368	-12,334
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,826	173,000
41	Total Tier 2 Pool Shortfall (MWh)	-98,292	-95,341
42	Augmentation Price ($/MWh)	$ 27.47	$ 29.63
43	Flat Block RSC ($/MWh)	$ 24.29	$ 26.43
44	Remarketing Value ($/MWh)	$ 27.47	$ 29.63
45	Remarketed Purchase (MWh)	12,368	12,334
46	Remarketed Purchase Cost	$ 339,750	$ 365,463
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	69,499	72,419
52	Total Fixed Costs	$ 18,069,688	$ 19,776,412
53	Billing Components		
54	Vintage.1 ($/MWh)	$ 44.72	$ 49.08
55	Remarketing Credit	$ 1,909,138	$ 2,145,775
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,791)	$ (534,328)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (58,549)	$ (58,389)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.12
Tier 2 VR1-2016 Rate Costing Table

	A	B	C
1		V.2.2016_2019	V.2.2016_2019
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 3,209,663	$ 6,051,808
6	Base Power Purchase Cost (Provided by PTL)	$ 3,031,798	$ 5,718,528
7	Power Purchase Cost	$ 3,031,798	$ 5,718,528
8	Transmission	$ -	$ -
9	Third Party PTP		
10	Ancillary Services		
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses		
15	Rate Design Components (Provided by PFR & PTM)	$ 111,393	$ 206,162
16	Resource Support Services	$ 11,455	$ 20,309
17	Diurnal Flattening Service	$ -	$ -
18	DFS Energy (Variable)		
19	DFS Capacity (Fixed)		
20	Forced Outage Reserve	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)		
22	Transmission Scheduling Services	$ 11,455	$ 20,309
23	Transmission Curtailment Management Service Capacity (Fixed)		
24	Transmission Curtailment Management Service Energy (Variable)		
25	Alternative Transmission Path Costs		
26	Generation Imbalance		
27	TSS - Overhead	$ 11,455	$ 20,309
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 99,937	$ 185,853
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	79,056	140,160
34	Tier 2 Obligation w/o losses (Billing Determinant)	79,056	140,160
35	Tier 2 Obligation w losses	81,476	144,450
36	Energy (Short)/Long (MWh)	-2,420	-4,290
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-2,420	-4,290
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,826	173,000
41	Total Tier 2 Pool Shortfall (MWh)	-98,292	-95,341
42	Augmentation Price ($/MWh)	$ 27.47	$ 29.63
43	Flat Block RSC ($/MWh)	$ 24.29	$ 26.43
44	Remarketing Value ($/MWh)	$ 27.47	$ 29.63
45	Remarketed Purchase (MWh)	2,420	4,290
46	Remarketed Purchase Cost	$ 66,473	$ 127,118
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	35,136	44,913
52	Total Fixed Costs	$ 3,209,663	$ 6,051,808
53	Billing Components		
54	Vintage.2 (VR1-2016) ($/MWh)	$ 40.60	$ 43.18
55	Remarketing Credit	$ 965,186	$ 1,330,772
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (99,937)	$ (185,853)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,455)	$ (20,309)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.13
Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J
1	**Start_Date**	**Maturity_Date**	**Trade_Date**	**Internal_Portfolio**	**Tran_Status**	**Hours**	**Price**	**Revenue**	**Position**	**Choice**
2	10/1/2015	9/30/2016	12/14/2011	Vintage T2	Validated	8784	$ 42.47	$ (17,160,598.08)	46.00	Seller's Choice
3	10/1/2015	9/30/2016	12/20/2011	Load Growth T2	Validated	8784	$ 42.47	$ (1,865,282.40)	5.00	Seller's Choice
4	10/1/2016	9/30/2017	12/14/2011	Vintage T2	Validated	8760	$ 46.70	$ (18,818,232.00)	46.00	Seller's Choice
5	10/1/2016	9/30/2017	12/20/2011	Load Growth T2	Validated	8760	$ 46.70	$ (2,045,460.00)	5.00	Seller's Choice
6	10/1/2015	9/30/2016	12/7/2012	Vintage T2	Validated	8784	$ 38.35	$ (3,031,797.60)	9.00	Seller's Choice
7	10/1/2016	9/30/2017	12/7/2012	Vintage T2	Validated	8760	$ 40.80	$ (5,718,528.00)	16.00	Seller's Choice

Table 3.13 (continued)
Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I
1	**Product**	**Term**	**Description**	**Reference**	**Tran_Num**	**Buy_Sell**	**RIS**	**Deal_Num**	**Pt_of_Receipt_Loc**
2	FLAT	Strip	Energy	related to # 245589	245590	Buy	79576	245281	MID-C
3	FLAT	Strip	Energy	related to # 245281	245589	Buy	79572	245589	MID-C
4	FLAT	Strip	Energy	related to # 245591	415275	Buy	79576	245282	MID-C
5	FLAT	Strip	Energy	related to # 245282	245591	Buy	79572	245591	MID-C
6	FLAT	Strip	Energy	Tier 2 Vintage FY16	314963	Buy	79577	314963	MID-C
7	FLAT	Strip	Energy	Tier 2 Vintage FY17	314976	Buy	79577	314965	MID-C

Table 3.14
Total Remarketing Charges and Credits

	A	B	C
1	Rate Period	BP-16	
2	Fiscal Year	FY2016	FY2017
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	34,433	33,707
5	Vintage.1 (VR1-2014) Remarket (MWh)	69,499	72,419
6	Vintage.2 (VR1-2016) Remarket (MWh)	35,136	44,913
7	Non-Federal Remarket (MWh)	40,758	21,961
8		179,826	173,000
9			
10	ShortTerm Purchase of Remarket (MWh)	83,504	78,716
11	LoadGrowth Purchase of Remarket (MWh)	0	0
12	Vintage.1 (VR1-2014) Purchase of Remarket (MWh)	12,368	12,334
13	Vintage.2 (VR1-2016) Purchase of Remarket (MWh)	2,420	4,290
14	BPA Purchase of Remarket (MWh)	81,534	77,659
15		179,826	173,000
16			
17	ShortTerm Remarket Credit	$ -	$ -
18	ShortTerm Remarket Charge	$ -	$ -
19	LoadGrowth Remarket Credit	$ -	$ -
20	LoadGrowth Remarket Charge	$ 516,489	$ 575,371
21	Vintage.1 (VR1-2014) Remarket Credit	$ 1,909,138	$ 2,145,775
22	Vintage.1 (VR1-2014) Remarket Charge	$ -	$ -
23	Vintage.2 (VR1-2016) Remarket Credit	$ 965,186	$ 1,330,772
24	Vintage.2 (VR1-2016) Remarket Charge	$ -	$ -
25	Non-Federal Resource Remarketing Credit	$ 1,119,622	$ 650,704
26			
27	ShortTerm Open Position (MWh)	0	0
28	LoadGrowth Open Position (MWh)	0	0
29	Vintage.1 (VR1-2014) Open Position (MWh)	0	0
30	Vintage.2 (VR1-2016) Open Position (MWh)	0	0
31	BPA Purchase of Remarket (MWh)	-81,534	-77,659
32	Total Open Position (MWh)	-81,534	-77,659

Table 3.15
Tier 2 Load Obligations

	A	B	C	D	E
1	**Sorting Key**	**Rate Pool**	**Fiscal Year**	**aMW Quantity w/o Losses**	**aMW Quantity w/ Losses (1)**
2	LG.1.2012_2028_FY2016	LG.1.2012_2028	FY2016	1.048	1.080
3	LG.1.2012_2028_FY2017	LG.1.2012_2028	FY2017	1.118	1.152
4	ST.2.2015_2019_FY2016	ST.2.2015_2019	FY2016	9.224	9.506
5	ST.2.2015_2019_FY2017	ST.2.2015_2019	FY2017	8.719	8.986
6	V.1.2014_2018_FY2016	V.1.2014_2018	FY2016	46.000	47.408
7	V.1.2014_2018_FY2017	V.1.2014_2018	FY2017	46.000	47.408
8	V.2.2016_2019_FY2016	V.2.2016_2019	FY2016	9.000	9.275
9	V.2.2016_2019_FY2017	V.2.2016_2019	FY2017	16.000	16.490
10					
11	*Notes*				
12	(1) Based on a losses factor of 3.06%				

Table 3.16
Customers Receiving a VR1-2014 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		**2016**						**2017**				
2		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket Credit**		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket Credit**
3	**Customers Remarketing VR1-2014 Purchases**	**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**		**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**
4	Big Bend Elec Coop	0.893	7,844	10.02%	$191,299	$15,942		0.367	3,215	4.44%	$95,258	$7,938
5	Burley, City of	1.000	8,784	11.22%	$214,221	$17,852		1.000	8,760	12.10%	$259,559	$21,630
6	Columbia Rural Electric Association, Inc.	1.093	9,601	12.26%	$234,144	$19,512		0.579	5,072	7.00%	$150,285	$12,524
7	Ellensburg, City of	0.600	5,270	6.73%	$128,533	$10,711		0.321	2,812	3.88%	$83,318	$6,943
8	Peninsula Light Company, Inc.	1.000	8,784	11.22%	$214,221	$17,852		1.000	8,760	12.10%	$259,559	$21,630
9	Richland, City of	4.299	37,762	48.24%	$920,936	$76,745		5.000	43,800	60.48%	$1,297,795	$108,150
10	Springfield Utility Board	0.000	-	0.00%	$0	$0		0.000	-	0.00%	$0	$0
11	Tanner Elec Coop	0.027	237	0.30%	$5,784	$482		0.000	-	0.00%	$0	$0
12	Total	8.912	78,283	100.00%	$1,909,138	$159,095		8.267	72,419	100.00%	$2,145,775	$178,815

Table 3.17
Customers Receiving a VR1-2016 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		**2016**						**2017**				
2		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket Credit**		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket Credit**
3	**Customers Remarketing VR1-2016 Purchases**	**aMW**	**MWH**	**Percentage**	**Allocation**	**Monthly**		**aMW**	**MWH**	**Percentage**	**Allocation**	**Monthly**
4	Big Bend Elec Coop		-	0.00%	$0	$0			-	0.00%	$0	$0
5	Burley, City of	1.000	8,784	33.33%	$321,729	$26,811		1.000	8,760	19.50%	$259,562	$21,630
6	Columbia Rural Electric Association, Inc.		-	0.00%	$0	$0			-	0.00%	$0	$0
7	Ellensburg, City of		-	0.00%	$0	$0			-	0.00%	$0	$0
8	Lower Valley	0.000	-	0.00%	$0	$0		0.440	3,854	8.58%	$114,207	$9,517
9	Peninsula Light Company, Inc.		-	0.00%	$0	$0			-	0.00%	$0	$0
10	Richland, City of		-	0.00%	$0	$0		0.687	6,018	13.40%	$178,319	$14,860
11	Springfield Utility Board	2.000	17,568	66.67%	$643,457	$53,621		3.000	26,280	58.51%	$778,685	$64,890
12	Tanner Elec Coop		-	0.00%	$0	$0			-	0.00%	$0	$0
13	Total	3.000	26,352	100.00%	$965,186	$80,432		5.127	44,913	100.00%	$1,330,772	$110,898

Table 3.18
Customers Receiving a FY 2016 Load Growth Customer Charge

	A	B	C	D	E	F	G	H
1			Tier 2	Load Growth	Remarketed			
2			Purchase	Usage	Amount			
3		Quantity (aMW)	5.00					
4		Quantity (MWh)	43,920	9,487	34,433			
5		Price	42.47	42.47	42.47			
6		Cost	$ 1,865,282	$ 402,930	$ 1,462,352			
7								
8		Remarket Price			27.47			
9		Remarket Credit			$ 945,863			
10		Stranded Cost			$ 516,489			
11								
12				AHWML	Allocation	Stranded Cost	Monthly	Premium on Load Shaping
13	FY 2016	Load Growth Pool Members		<1 aMW	Percentage	Allocation	Allocation	$/MWh
14	10055	Albion, City of		0.008	0.100%	$ 518	$ 43	$ 7.37
15	10059	Alder Mutual		0	0.000%	$ -	$ -	$ -
16	10015	Asotin County PUD #1		0.023	0.288%	$ 1,489	$ 124	$ 7.37
17	10065	Bandon, City of		0	0.000%	$ -	$ -	$ -
18	10025	Benton REA		0	0.000%	$ -	$ -	$ -
19	10061	Blaine, City of		0.737	9.237%	$ 47,707	$ 3,976	$ 7.37
20	10068	Cascade Locks, City of		0	0.000%	$ -	$ -	$ -
21	10082	Chewelah, City of		0	0.000%	$ -	$ -	$ -
22	10109	Columbia Basin Elec Coop		0.614	7.695%	$ 39,745	$ 3,312	$ 7.37
23	10116	Columbia Power Coop		0	0.000%	$ -	$ -	$ -
24	10144	Consolidated Irrigation District #19		0	0.000%	$ -	$ -	$ -
25	10378	Coulee Dam, City of		0.047	0.589%	$ 3,042	$ 254	$ 7.37
26	10070	Declo, City of		0.019	0.238%	$ 1,230	$ 102	$ 7.37
27	10071	Drain, City of		0.043	0.539%	$ 2,783	$ 232	$ 7.37
28	10142	East End Mutual Electric		0.394	4.938%	$ 25,504	$ 2,125	$ 7.37
29	10156	Eatonville, City of		0	0.000%	$ -	$ -	$ -
30	10172	Elmhurst Mutual P & L		0	0.000%	$ -	$ -	$ -
31	10174	Farmers Elec Coop		0.013	0.163%	$ 842	$ 70	$ 7.37
32	10177	Ferry County PUD #1		0.789	9.888%	$ 51,073	$ 4,256	$ 7.37
33	10190	Grant County PUD #2		0.405	5.076%	$ 26,216	$ 2,185	$ 7.37
34	10197	Harney Elec Coop		0.557	6.981%	$ 36,055	$ 3,005	$ 7.37
35	10597	Hermiston, City of		0	0.000%	$ -	$ -	$ -
36	10202	Hood River Elec Coop		0.713	8.936%	$ 46,153	$ 3,846	$ 7.37
37	10230	Kittitas County PUD #1		0.868	10.879%	$ 56,187	$ 4,682	$ 7.37
38	10256	Lakeview L & P (WA)		0	0.000%	$ -	$ -	$ -
39	10242	Lost River Elec Coop		0.029	0.363%	$ 1,877	$ 156	$ 7.37
40	10246	Mason County PUD #1		0.322	4.036%	$ 20,843	$ 1,737	$ 7.37
41	10260	Midstate Elec Coop		0	0.000%	$ -	$ -	$ -
42	10080	Milton, Town of		0.515	6.454%	$ 33,336	$ 2,778	$ 7.37
43	10111	Minidoka, City of		0	0.000%	$ -	$ -	$ -
44	10273	Modern Elec Coop		0	0.000%	$ -	$ -	$ -
45	10083	Monmouth, City of		0.018	0.226%	$ 1,165	$ 97	$ 7.37
46	10005	Nespelem Valley Elec Coop		0	0.000%	$ -	$ -	$ -
47	10284	Ohop Mutual Light Company		0	0.000%	$ -	$ -	$ -
48	10288	Orcas P & L		0.097	1.216%	$ 6,279	$ 523	$ 7.37
49	10291	Oregon Trail Coop		0	0.000%	$ -	$ -	$ -
50	10304	Parkland L & W		0	0.000%	$ -	$ -	$ -
51	10086	Plummer, City of		0.054	0.677%	$ 3,495	$ 291	$ 7.37
52	10338	Riverside Elec Coop		0.153	1.918%	$ 9,904	$ 825	$ 7.37
53	10342	Salem Elec Coop		0	0.000%	$ -	$ -	$ -
54	10352	Skamania County PUD #1		0	0.000%	$ -	$ -	$ -
55	10360	Southside Elec Lines		0.567	7.106%	$ 36,702	$ 3,059	$ 7.37
56	10379	Steilacoom, Town of		0.135	1.692%	$ 8,739	$ 728	$ 7.37
57	10095	Sumas, Town of		0.078	0.978%	$ 5,049	$ 421	$ 7.37
58	10097	Troy, City of		0.152	1.905%	$ 9,839	$ 820	$ 7.37
59	10235	U.S. Air Force Base, Fairchild		0	0.000%	$ -	$ -	$ -
60	10406	U.S. DOE Albany Research Center		0.074	0.927%	$ 4,790	$ 399	$ 7.37
61	10326	U.S. Naval Base, Bremerton		0	0.000%	$ -	$ -	$ -
62	10408	U.S. Naval Station, Everett (Jim Creek)		0	0.000%	$ -	$ -	$ -
63	10409	U.S. Naval Submarine Base, Bangor		0.036	0.451%	$ 2,330	$ 194	$ 7.37
64	10482	Umpqua Indian Utility Cooperative		0	0.000%	$ -	$ -	$ -
65	10440	Wahkiakum County PUD #1		0.12	1.504%	$ 7,768	$ 647	$ 7.37
66	10442	Wasco Elec Coop		0	0.000%	$ -	$ -	$ -
67	11680	Weiser, City of		0.399	5.001%	$ 25,828	$ 2,152	$ 7.37
68		Total		7.979	100.00%	$ 516,489	$ 43,041	

Table 3.19
Customers Receiving a FY 2017 Load Growth Customer Charge

	A	B	C	D	E	F	G	H
1			Tier 2	Load Growth	Remarketed			
2			Purchase	Usage	Amount			
3		Quantity (aMW)	5.00					
4		Quantity (MWh)	43,800	10,093	33,707			
5		Price	$ 46.70	$ 46.70	$ 46.70			
6		Cost	$ 2,045,460	$ 471,364	$ 1,574,096			
7								
8		Remarket Price			$ 29.63			
9		Remarket Credit			$ 998,725			
10		Stranded Cost			$ 575,371			
11								
12				AHWML	Allocation	Stranded Cost	Monthly	Premium on Load Shaping
13	FY 2017 Load Growth Pool Members			<1 aMW	Percentage	Allocation	Allocation	$/MWh
14	10055	Albion, City of		0.011	0.108%	$ 624	$ 52	$ 6.46
15	10005	Alder Mutual		0	0.000%	$ -	$ -	$ -
16	10015	Asotin County PUD #1		0.029	0.286%	$ 1,645	$ 137	$ 6.46
17	10059	Bandon, City of		0.029	0.286%	$ 1,645	$ 137	$ 6.46
18	10025	Benton REA		0	0.000%	$ -	$ -	$ -
19	10061	Blaine, City of		0.867	8.545%	$ 49,167	$ 4,097	$ 6.46
20	10065	Cascade Locks, City of		0	0.000%	$ -	$ -	$ -
21	10068	Chewelah, City of		0	0.000%	$ -	$ -	$ -
22	10109	Columbia Basin Elec Coop		0.656	6.466%	$ 37,201	$ 3,100	$ 6.46
23	10111	Columbia Power Coop		0	0.000%	$ -	$ -	$ -
24	10116	Consolidated Irrigation District #19		0	0.000%	$ -	$ -	$ -
25	10378	Coulee Dam, City of		0.084	0.828%	$ 4,764	$ 397	$ 6.46
26	10070	Declo, City of		0.019	0.187%	$ 1,077	$ 90	$ 6.46
27	10071	Drain, City of		0.047	0.463%	$ 2,665	$ 222	$ 6.46
28	10142	East End Mutual Electric		0.446	4.396%	$ 25,292	$ 2,108	$ 6.46
29	10144	Eatonville, City of		0.003	0.030%	$ 170	$ 14	$ 6.46
30	10156	Elmhurst Mutual P & L		0.175	1.725%	$ 9,924	$ 827	$ 6.46
31	10174	Farmers Elec Coop		0.016	0.158%	$ 907	$ 76	$ 6.46
32	10177	Ferry County PUD #1		0.919	9.058%	$ 52,116	$ 4,343	$ 6.46
33	10190	Grant County PUD #2		0.474	4.672%	$ 26,880	$ 2,240	$ 6.46
34	10197	Harney Elec Coop		0.632	6.229%	$ 35,840	$ 2,987	$ 6.46
35	10597	Hermiston, City of		0	0.000%	$ -	$ -	$ -
36	10202	Hood River Elec Coop		0.887	8.742%	$ 50,301	$ 4,192	$ 6.46
37	10230	Kittitas County PUD #1		0.958	9.442%	$ 54,327	$ 4,527	$ 6.46
38	10235	Lakeview L & P (WA)		0	0.000%	$ -	$ -	$ -
39	10242	Lost River Elec Coop		0.117	1.153%	$ 6,635	$ 553	$ 6.46
40	10246	Mason County PUD #1		0.356	3.509%	$ 20,188	$ 1,682	$ 6.46
41	10256	Midstate Elec Coop		0	0.000%	$ -	$ -	$ -
42	10080	Milton, Town of		0.579	5.707%	$ 32,835	$ 2,736	$ 6.46
43	10082	Minidoka, City of		0	0.000%	$ -	$ -	$ -
44	10260	Modern Elec Coop		0	0.000%	$ -	$ -	$ -
45	10083	Monmouth, City of		0.063	0.621%	$ 3,573	$ 298	$ 6.46
46	10273	Nespelem Valley Elec Coop		0	0.000%	$ -	$ -	$ -
47	10284	Ohop Mutual Light Company		0	0.000%	$ -	$ -	$ -
48	10288	Orcas P & L		0.162	1.597%	$ 9,187	$ 766	$ 6.46
49	10291	Oregon Trail Coop		0.478	4.711%	$ 27,107	$ 2,259	$ 6.46
50	10304	Parkland L & W		0.009	0.089%	$ 510	$ 43	$ 6.46
51	10086	Plummer, City of		0.097	0.956%	$ 5,501	$ 458	$ 6.46
52	10338	Riverside Elec Coop		0.191	1.883%	$ 10,831	$ 903	$ 6.46
53	10342	Salem Elec Coop		0	0.000%	$ -	$ -	$ -
54	10352	Skamania County PUD #1		0	0.000%	$ -	$ -	$ -
55	10360	Southside Elec Lines		0.662	6.525%	$ 37,541	$ 3,128	$ 6.46
56	10379	Steilacoom, Town of		0.169	1.666%	$ 9,584	$ 799	$ 6.46
57	10095	Sumas, Town of		0.1	0.986%	$ 5,671	$ 473	$ 6.46
58	10097	Troy, City of		0.182	1.794%	$ 10,321	$ 860	$ 6.46
59	10172	U.S. Air Force Base, Fairchild		0	0.000%	$ -	$ -	$ -
60	10406	U.S. DOE Albany Research Center		0.075	0.739%	$ 4,253	$ 354	$ 6.46
61	10326	U.S. Naval Base, Bremerton		0	0.000%	$ -	$ -	$ -
62	10408	U.S. Naval Station, Everett (Jim Cr		0	0.000%	$ -	$ -	$ -
63	10409	U.S. Naval Submarine Base, Bango		0.051	0.503%	$ 2,892	$ 241	$ 6.46
64	10482	Umpqua Indian Utility Cooperative		0	0.000%	$ -	$ -	$ -
65	10440	Wahkiakum County PUD #1		0.121	1.193%	$ 6,862	$ 572	$ 6.46
66	10442	Wasco Elec Coop		0	0.000%	$ -	$ -	$ -
67	11680	Weiser, City of		0.482	4.751%	$ 27,334	$ 2,278	$ 6.46
68		Total		10.146	100.00%	$ 575,371	$ 47,948	

Table 3.20
Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	F	G	H	I	J
1		Monthly Irrigation Rate Mitigation Amounts from Exhibit D of the Regional Dialogue Contracts (in MWh)								
2	BES ID	Customer Name	May	June	July	August	September	TOTAL	Eligible LDD	Total IRD MWh * LDD %
3	10024	Benton PUD	53,115.401	75,243.324	89,003.560	62,842.958	32,033.957	312,239.200	0.00%	0.000
4	10183	Franklin PUD	13,084.284	22,897.496	23,715.264	22,079.728	12,630.475	94,407.247	0.00%	0.000
5	10231	Klickitat	3,082.499	4,137.060	5,575.639	4,578.816	4,258.715	21,632.729	7.00%	1,514.291
6	10286	Okanogan PUD	7,203.742	10,441.534	14,718.217	12,876.538	10,168.120	55,408.151	0.00%	0.000
7	10025	Benton REA	11,147.270	18,681.537	24,281.424	19,190.846	9,599.780	82,900.857	6.50%	5,388.556
8	10027	Big Bend	32,097.789	47,948.108	50,352.318	47,379.798	31,891.527	209,669.540	7.00%	14,676.868
9	10391	United	5,273.820	10,806.706	12,770.236	9,182.704	6,236.687	44,270.153	3.50%	1,549.455
10	10046	Central Elec	4,687.388	8,675.756	9,539.100	10,094.599	8,088.614	41,085.457	7.00%	2,875.982
11	10109	Columbia Basin	4,185.302	5,469.756	4,513.543	3,665.441	3,266.293	21,100.335	7.00%	1,477.023
12	10111	Columbia Power	706.641	866.742	1,530.227	1,432.169	691.870	5,227.649	7.00%	365.935
13	10113	Columbia REA	21,258.914	30,832.646	36,368.973	29,431.678	16,763.751	134,655.962	7.00%	9,425.917
14	10173	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3,101.700
15	10197	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6,992.944
16	10209	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4,207.889
17	10242	Lost River	3,725.641	9,902.214	10,705.288	8,479.424	4,746.327	37,558.894	7.00%	2,629.123
18	10256	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	6.50%	2,696.805
19	10273	Nespelem	1,216.565	1,778.549	2,517.152	2,274.786	1,734.973	9,522.025	7.00%	666.542
20	10291	OTEC	4,715.415	7,780.401	10,076.149	7,938.224	5,750.412	36,260.601	5.00%	1,813.030
21	10331	Raft River	23,443.131	30,794.718	32,636.209	27,344.114	18,868.686	133,086.858	7.00%	9,316.080
22	10142	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	2.50%	144.237
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.50%	145.432
24	10360	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	4.50%	900.420
25	10343	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	5.50%	577.811
26	10369	Surprise Valley	6,464.252	9,066.424	11,421.596	11,671.642	7,586.987	46,210.901	7.00%	3,234.763
27	10388	Umatilla	39,288.078	52,679.345	55,478.176	49,073.469	32,253.359	228,772.427	6.00%	13,726.346
28	10442	Wasco	1,883.529	2,101.872	2,215.155	1,766.387	1,766.387	9,733.330	7.00%	681.333
29	10446	Wells	846.538	1,717.671	1,928.492	1,812.765	865.874	7,171.340	5.00%	358.567
30	10502	Yakama Power	1,463.062	1,175.985	1,228.497	1,619.426	1,702.727	7,189.697	0.00%	0.000
31	10436	Vigilante	5,362.005	10,090.787	11,936.481	8,014.268	3,459.717	38,863.258	7.00%	2,720.428
32	10258	Mission Valley	1,857.275	3,714.550	6,500.462	5,571.825	742.910	18,387.022	6.50%	1,195.156
33								Wt. LDD	4.9%	

Table 3.21
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017

	A	B	C	D	E	F	G
1	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"ResourceInput" Tab Adj. for Schedule Annual aMW	Exh. A FY2016 Annual aMW	Exh. A FY2017 Annual aMW
2	Benton Rural Electric Association	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	3.447	4.423
3	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	1.000	1.000
4	Tier 1	Klondike 3	DFS TSS TCMS RSC	FY2016&FY2017	14.722	15.923	15.945
5	City of Bonners Ferry	Moyie	GMS	FY2016&FY2017	N/A	1.878	1.881
6	City of Centralia	Yelm Hydro	GMS	FY2016&FY2017	N/A	7.109	7.114
7	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2017	N/A	0.000	1.000
8	City of Forest Grove	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454	1.454
9	City of Forest Grove	Wanapum	SCS	FY2016&FY2017	N/A	1.481	1.482
10	The City of McMinnville, a municipal corporation c	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454	1.454
11	The City of McMinnville, a municipal corporation c	Wanapum	SCS	FY2016&FY2017	N/A	1.481	1.482
12	The City of McMinnville, a municipal corporation c	Riverbend Biogas	DFS FOR RSC	FY2016&FY2017	4.173	4.069	4.069
13	City of Milton-Freewater	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454	1.454
14	City of Milton-Freewater	Wanapum	SCS	FY2016&FY2017	N/A	1.481	1.482
15	Wells REC	Unspecified Resource Amounts	TSS TCMS	FY2017	N/A	0.000	2.000
16	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2016&FY2017	1.397	0.673	0.673
17	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2016&FY2017	1.477	1.231	1.231
18	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2016&FY2017	1.121	1.077	1.077
19	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2016&FY2017	1.916	2.499	2.500
20	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2016&FY2017	N/A	0.484	0.484
21	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2016&FY2017	N/A	0.494	0.494
22	Lower Valley Energy, Inc.	Horse Butte	DFS TSS RSC	FY2017	2.505	0.000	2.573
23	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2016&FY2017	N/A	0.656	0.656
24	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2016&FY2017	0.852	0.809	0.809
25	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2016&FY2017	0.994	0.919	0.920
26	Mission Valley Power	Kerr	TSS TCMS	FY2016&FY2017	N/A	9.651	9.657
27	PNGC	Lake Creek	SCS	FY2016&FY2017	N/A	1.527	1.530
28	PNGC	Chester Hydro	DFS FOR RSC	FY2016&FY2017	0.489	0.966	0.967
29	PNGC	Island Park	SCS	FY2016&FY2017	N/A	0.989	0.992
30	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	21.000	23.000
31	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	51.497	52.000
32	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2016&FY2017	N/A	4.405	4.404
33	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	15.000	22.000
34	Peninsula Light Company	Harvest Wind	DFS TSS TCMS RSC	FY2016	2.005	2.000	0.000
35	Peninsula Light Company	Harvest Wind	DFS TSS TCMS RSC	FY2017	3.007	0.000	3.000

Table 3.21 (continued)
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	DFS Capacity $/MWh Equiv.	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	FOR Capacity $/MWh Equiv.	TSS $/mo	TSS $/MWh Equiv.	TCMS $/mo	TCMS $/MWh Equiv.	SCS $/mo	SCS $/MWh Equiv.	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY2016	Revenue Credit to Non-Slice Cost Pool FY2016	Revenue Credit to Composite Cost Pool FY2017	Revenue Credit to Non-Slice Cost Pool FY2017	Forecast Total $/MWh Equivalent Rate
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 419	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,032	$ -	$ 5,032	$ -	$ 0.15
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 119	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,428	$ -	$ 1,428	$ -	$ 0.16
4	$ 2.81	$ 142,741	$ 13.28	$ 29,848	$ 2.78	$ -	$ -	$ 995	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,724,827	$ 720,332	$ 1,724,827	$ 720,332	$ 18.96
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 866	$ 0.63	$ 10,389	$ -	$ 10,389	$ -	$ 0.63
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,524	$ 0.68	$ 42,292	$ -	$ 42,292	$ -	$ 0.68
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 119	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,426	$ -	$ 0.16
8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,124	$ -	$ 8,124	$ -	$ 0.64
9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690	$ 0.64	$ -	$ -	$ 8,274	$ -	$ 8,274	$ -	$ 0.64
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,124	$ -	$ 8,124	$ -	$ 0.64
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690	$ 0.64	$ -	$ -	$ 8,274	$ -	$ 8,274	$ -	$ 0.64
12	$ 0.18	$ 10,989	$ 3.61	$ (2,948)	$ (0.97)	$ 2,078	$ 0.68	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,803	$ (28,924)	$ 156,803	$ (28,924)	$ 3.50
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,124	$ -	$ 8,124	$ -	$ 0.64
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 690	$ 0.64	$ -	$ -	$ 8,274	$ -	$ 8,274	$ -	$ 0.64
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 221	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,653	$ -	$ 0.15
16	$ 0.93	$ 8,707	$ 8.54	$ (14,475)	$ (14.19)	$ 246	$ 0.24	$ 86	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,465	$ (162,377)	$ 108,465	$ (162,377)	$ (4.40)
17	$ 0.37	$ 4,549	$ 4.22	$ (4,442)	$ (4.12)	$ 501	$ 0.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,600	$ (48,505)	$ 60,600	$ (48,505)	$ 0.93
18	$ 0.11	$ 2,123	$ 2.59	$ (1,538)	$ (1.88)	$ 620	$ 0.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,913	$ (17,350)	$ 32,913	$ (17,350)	$ 1.58
19	$ 0.24	$ 12,648	$ 9.04	$ (1,052)	$ (0.75)	$ 431	$ 0.31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,944	$ (8,573)	$ 156,944	$ (8,573)	$ 8.84
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225	$ 0.64	$ -	$ -	$ 2,705	$ -	$ 2,705	$ -	$ 0.64
21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 230	$ 0.64	$ -	$ -	$ 2,756	$ -	$ 2,756	$ -	$ 0.64
22	$ 2.31	$ 24,055	$ 13.16	$ 1,399	$ 0.77	$ -	$ -	$ 280	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 292,015	$ 67,381	$ 16.39
23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 73	$ 0.15	$ -	$ -	$ 315	$ 0.66	$ -	$ -	$ 4,649	$ -	$ 4,649	$ -	$ 0.81
24	$ 3.09	$ 7,887	$ 12.68	$ (529)	$ (0.85)	$ -	$ -	$ 88	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 95,704	$ 16,712	$ 95,704	$ 16,712	$ 15.06
25	$ 2.82	$ 9,400	$ 12.95	$ (1,025)	$ (1.41)	$ -	$ -	$ 100	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,996	$ 12,247	$ 113,996	$ 12,247	$ 14.50
26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 995	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,935	$ -	$ 11,935	$ -	$ 0.14
27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 697	$ 0.62	$ -	$ -	$ 8,364	$ -	$ 8,364	$ -	$ 0.62
28	$ 0.37	$ 1,922	$ 5.38	$ 8,886	$ 24.88	$ 119	$ 0.33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,494	$ 108,214	$ 24,494	$ 108,214	$ 30.96
29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 458	$ 0.63	$ -	$ -	$ 5,501	$ -	$ 5,501	$ -	$ 0.63
30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,260	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,116	$ -	$ 27,116	$ -	$ 0.14
31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,942	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,304	$ -	$ 35,304	$ -	$ 0.08
32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 459	$ 0.14	$ -	$ -	$ -	$ -	$ 2,170	$ 0.67	$ 31,549	$ -	$ 31,549	$ -	$ 0.81
33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,901	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,814	$ -	$ 22,814	$ -	$ 0.14
34	$ 2.82	$ 18,974	$ 12.97	$ 850	$ 0.58	$ -	$ -	$ 222	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 230,348	$ 59,665	$ -	$ -	$ 16.52
35	$ 2.82	$ 28,459	$ 12.97	$ 1,112	$ 0.51	$ -	$ -	$ 323	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 345,387	$ 87,527	$ 16.45

Table 3.22
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS.

	A	B	C	D	E	F
1		**2016**				
2		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket**
3	**Customers Remarketing 2016 Non-Federal Resource Purchases**	**aMW**	**MWH**	**Percentage**	**Allocation**	**Monthly Credit**
4	Flathead Electric Cooperative, Inc.	1.700	14,933	36.64%	$410,206	$34,184
5	Peninsula Light Company	1.952	17,146	42.07%	$471,013	$39,251
6	Public Utility District No. 3 of Mason County, Washington: Nine Canyon Resource	0.988	8,679	21.29%	$238,402	$19,867
7	**Total**	**4.640**	**40,758**	**100.00%**	**$1,119,622**	**$93,302**
8						
9						
10		**2017**				
11		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarket Credit**	**Remarket**
12	**Customers Remarketing 2017 Non-Federal Resource Purchases**	**aMW**	**MWH**	**Percentage**	**Allocation**	**Monthly Credit**
13	Peninsula Light Company	1.947	17,056	77.66%	$505,353	$42,113
14	Public Utility District No. 3 of Mason County, Washington: White Creek Resource	0.560	4,906	22.34%	$145,351	$12,113
15	**Total**	**2.507**	**21,961**	**100.00%**	**$650,704**	**$54,225**

Table 3.23
WECC and Peak Dues Charge Calculation

A	B	C	D	E
Balancing Authority Area (BAA)	**NEL as reported by BAA (MWh)**	**WECC Dues Rate ($0.0424/MWh)**	**Peak Dues Rate ($0.056/MWh)**	
Avista				
1. Subtotal (Losses Included)	1,851,401	$78,499	$103,678	
2. Subtotal (Losses Removed)	1,795,859			
Idaho Power				
3. Subtotal (Losses Included)	1,864,617	$79,060	$104,419	
4. Subtotal (Losses Removed)	1,797,491			
Portland General Electric				
5. Subtotal (Losses Included)	505,247	$21,422	$28,294	
6. Subtotal (Losses Removed)	497,719			
Puget Sound Energy				
7. Subtotal (Losses Included)	365,995	$15,518	$20,496	
8. Subtotal (Losses Removed)	356,077			
Northwestern				
9. Subtotal (Losses Included)	779,199	$33,038	$43,635	
10. Subtotal (Losses Removed)	748,031			
Nevada Energy (Sierra Pacific)				
11. Subtotal (Losses Included)	763,129	$32,357	$42,735	
12. Subtotal (Losses Removed)	732,604			
Grant PUD				
13. Subtotal (Losses Included)	44,719	$1,896	$2,504	
14. Subtotal (Losses Removed)	43,154			
15. Total (Sum Lines 1-14)	5,970,934	$261,791	$345,761	
16. 2016 Inflation Rate		1.68%	1.68%	
17. 2017 Inflation Rate		1.60%	1.60%	
18. Total NEL of BAAs that roll ALL WECC & Peak Dues into their rates (MWh)	3,071,682	$266,189	$351,570	2016 RR
		$270,448	$357,195	2017 RR
		$268,318	$354,383	RRavg
19. Non-BPA BAA Transfer Service CustomerTotal NEL (Sum Lines 15-18)	9,042,616			
20. Non-BPA BAA Transfer Service Customer WECC Dues Rate* ($/MWh)	$0.0297			
21. Non-BPA BAA Transfer Service Customer Peak Dues Rate* ($/MWh)	$0.0392			

Table 3.24
Southeast Idaho Load Service Five-Year Market Purchases

Step 1: $((SM_H * S_H) + (SM_L * S_L)) / S_F = SM_F$

Step 1 calculates the combined summer flat weighted average megawatts associated with the five-year market purchases (SM_F). *See* Documentation Table 3.24, line 4. Summer and winter portions of the contract are addressed separately because of the different megawatt amounts associated with each period. This is achieved by taking the summer contracted megawatts multiplied by the associated hours for both heavy and light load, then dividing by the total hours for that period.

Step 2: $((WM_H * W_H) + (WM_L * W_L)) / W_F = WM_F$

Step 2 calculates the combined winter flat weighted average megawatts associated with the five-year market purchases (WM_F). *See* Documentation Table 3.24, line 12. The calculation process for the winter equation is the same as the summer equation described in line 4.

Step 3: $SUM\ (W_F, S_F) = TCH$

Step 3 calculates the sum of all megawatt hours associated with the market purchases (TCH) in line 17.

Step 4: $((SM_F * S_F) + (WM_F * W_F)) / SUM\ (W_F, S_F) = TCM$

Once the combined flat weighted average has been calculated for the summer and winter portions of the market purchase, Step 4 calculates flat weighted average megawatts for the entire market purchase (TCM) on line 19.

Step 5: $((M_1 * RMh_1) + (M_2 * RMh_2)) / TCH = WFM$

Step 5 calculates the weighted average forward market price (WFM) using the ICE forward market curves established at the time each purchase was finalized. To do so, the weighted average market price represented by "M" for each purchase is multiplied by its respective megawatthours (RMH) and then divided by the total megawatthours to yield the WFM, on line 21.

Step 6: $((R_1 * RMh_1) + (R_2 * RMh_2)) / TCH = WCP$

Step 6 follows the same steps as in steps 1 through 5 but uses each contract's offer price in place of the ICE forward market price to yield the weighted average contract price (WCP), on line 23.

Step 7: $(TCH * TCM * WCP) = TCC$

Step 7 multiplies the results from steps 3, 4, and 6 to yield the Total Contract Cost (TCC) on line 25.

Step 8: $(WCP – WFM) = AMD$

Step 8 subtracts the result from Step 6 from the result in Step 5 to yield the Average Market Delta (AMD). The AMD will help determine the total cost to the transfer service customers, on line 27.

Step 9: $(AMD * TCM) = T$

Step 9 multiplies the Average Market Delta by the TCM to yield the Total Transfer Service Cost (T) on line 29. Monthly values are shown in Table 3.25.

Parameter Definitions

AMD = Average Market Delta
M_H = Month heavy hours
M_L = Month light hours
M_1 = weighted forward market purchase #1 price
M_2 = weighted forward market purchase #2 price
R_1 = Market purchase #1 offer price
R_2 = Market purchase #2 offer price
R_A = RFO 1 & 2 weighted average market price
RMh_1 = Market purchase #1 contract MW hours
RMh_2 = Market purchase #2 contract MW hours
S_F = summer flat hours
S_H = summer heavy hours
S_L = summer light hours
SM_F = summer market purchase contract total MW flat
SM_H = summer market purchase contract total MW heavy
SM_L = summer market purchase contract total MW light
T = Transfer service cost
TCB = Total Contract Cost
TCH = Total Contract Megawatt hours
TCM = Total Contract average Megawatts
W_F = winter flat hours
W_H = winter heavy hours
W_L = winter light hours
WCP = Weighted average Contract Price
WFM = Weighted average Forward Market price
WM_F = winter market purchase contract MW flat load
WM_H = winter market purchase contract MW heavy load
WM_L = winter market purchase contract MW light load

Table 3.24 (continued)
Southeast Idaho Load Service Five-Year Market Purchases

	A	B	C	D
1	**Summer**	**MW**	**MWh**	**MW (SMF)**
2	HLH	125	1,538,000	
3	LLH	50	482,800	
4	Step 1. Flat			92
5				
6	**Summer**	**HLH**	**LLH**	**Flat**
7	Hours	12,304	9656	21,960
8				
9	**Winter**	**MW**	**MWh**	**MW (WMF)**
10	HLH	125	1,532,000	
11	LLH	100	960,800	
12	Step 2. Flat			114
13				
14	**Winter**	**HLH**	**LLH**	**Flat**
15	Hours	12,256	9,608	21,864
16				
17	Step 3. Total Contract Hours (TCH)			43,824
18				
19	Step 4. Total aMW (TCM)			103
20				
21	Step 5. Market (WFM)			$42.59
22				
23	Step 6. RFO (WCP)			$48.61
24				
25	Step 7. Total Contract Cost (TCC)			$219,386,064
26				
27	Step 8. Delta (AMD)			$6.01
28				
29	Step 9. Total Transfer Service Cost (T)			$27,131,407

Table 3.25
Southeast Idaho Load Service Market Purchases - Monthly Power Purchase Segmented by Cost Pool and by Fiscal Year

	A	B	C	D	E	F	G
		Composite Delta		**Non Slice Allocation**		**Total Purchase Cost**	
	Month	**FY 2016**	**FY 2017**	**FY 2016**	**FY 2017**	**FY 2016**	**FY 2017**
1	October		$ 509,648		$ 3,612,442		$ 4,122,090
2	November		$ 493,421		$ 3,497,423		$ 3,990,844
3	December		$ 509,648		$ 3,612,442		$ 4,122,090
4	January		$ 507,244		$ 3,595,402		$ 4,102,646
5	February		$ 461,568		$ 3,271,645		$ 3,733,213
6	March		$ 511,451		$ 3,625,222		$ 4,136,673
7	April		$ 396,660		$ 2,811,570		$ 3,208,230
8	May		$ 411,084		$ 2,913,809		$ 3,324,893
9	June		$ 403,872		$ 2,862,690		$ 3,266,562
10	July	$ 403,872	$ 403,872	$ 2,862,690	$ 2,862,690	$ 3,266,562	$ 3,266,562
11	August	$ 418,296	$ 418,296	$ 2,964,929	$ 2,964,929	$ 3,383,225	$ 3,383,225
12	September	$ 396,660	$ 396,660	$ 2,811,570	$ 2,811,570	$ 3,208,230	$ 3,208,230
13	FY Total (Sum lines 1-12)	$ 1,218,828	$ 5,423,424	$ 8,639,188	$ 38,441,832	$ 9,858,016	$ 43,865,256
14	Total Service Cost		**$ 6,642,252**		**$ 47,081,021**		**$ 53,723,273**

Monthly Cost Breakdown

Table 3.25 displays the total monthly costs resulting from lines 21 (columns D & E), 23 (columns F & G), and 27 (columns B & C) of table 3.24. To do this additional calculations are needed. The average market delta (AMD) established in Step 8 of Table 3.24 is applied to the following formula $((M_H * SM_H) + (M_L * SM_L)) *$ AMD. The Monthly heavy and light hours are multiplied by the contracted megawatt hours in the market purchases, and then multiplied by the average market delta resulting in the amounts shown in the table above. For the FY 2016 and 2017 rates, the annual totals for each fiscal year are added to the transfer services budget and thus included in the composite cost pool. Swaping out AMD for WFM (line 21) or WCP (line 23) will get the results in columns D & E and F & G respectivly.

SECTION 4: REVENUE FORECAST

Table Descriptions

Table 4.1 Revenue at Current Rates
Table provides breakdown of revenue and power purchases at current rates.

Table 4.2 Revenue at Proposed Rates
Table provides breakdown of revenue and power purchases at proposed rates.

Table 4.3 Composite and Non-Slice Revenue – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.4 Load Shaping and Demand Review – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.5 Irrigation Rate Discount (IRD) – FY 2016-2017
Table shows calculation of IRD credit at proposed rates.

Table 4.6 Low Density Discount (LDD) – FY 2016-2017
Table shows calculation of LDD credit at proposed rates.

Table 4.7 Tier 2 Revenue – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.8 Direct Service Industries (DSI) Revenues – FY 2016-2017
Table shows calculation of DSI revenues at current and proposed rates.

Table 4.1 - Revenue at Current Rates

	B C D E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**Table 4.1 - Revenue at Current Rates**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 191,650	$ 191,650	$ 191,650	$ 191,650	$ 191,650	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 2,300,218	5,063
4	Non-Slice Revenue	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (257,365)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,862
6	Load Shaping Revenue	$ (3,835)	$ (6,636)	$ 7,224	$ 7,558	$ 7,874	$ 12,040	$ 20,571	$ (28,892)	$ (17,137)	$ (16,170)	$ (3,925)	$ 1,120	$ (20,208)	19
7	Demand Revenue	$ 1,443	$ 7,360	$ 11,820	$ 4,667	$ 3,163	$ 3,817	$ 3,325	$ 1,791	$ 2,342	$ 3,595	$ 3,772	$ 3,290	$ 50,386	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,900)	$ (4,335)	$ (4,992)	$ (4,097)	$ (2,492)	$ (18,816)	-
9	Low Density Discount	$ (2,622)	$ (2,710)	$ (3,105)	$ (2,824)	$ (2,726)	$ (3,011)	$ (3,363)	$ (2,258)	$ (2,541)	$ (2,721)	$ (2,931)	$ (2,879)	$ (33,691)	-
10	Tier 2	$ 2,186	$ 2,169	$ 2,186	$ 2,186	$ 1,964	$ 2,281	$ 2,210	$ 2,284	$ 2,210	$ 2,284	$ 2,284	$ 2,195	$ 26,439	75
11	RSS (Non-Federal)	$ 172	$ 50	$ 47	$ 111	$ 170	$ (51)	$ (48)	$ (54)	$ (50)	$ (52)	$ (53)	$ (50)	$ 191	-
12	**PF customers (TRM) sub-total**	**$ 167,551**	**$ 170,440**	**$ 188,380**	**$ 181,906**	**$ 180,653**	**$ 185,335**	**$ 192,955**	**$ 140,229**	**$ 150,749**	**$ 152,203**	**$ 165,309**	**$ 171,445**	**$ 2,043,973**	**7,019**
13	**NR sub-total**	**$ (56)**	**$ (106)**	**$ (110)**	**$ (159)**	**$ (153)**	**$ (155)**	**$ (122)**	**$ (110)**	**$ (120)**	**$ (163)**	**$ (198)**	**$ (198)**	**$ (1,649)**	**-**
14	**DSIs sub-total**	**$ 9,283**	**$ 9,770**	**$ 10,808**	**$ 10,397**	**$ 9,416**	**$ 8,845**	**$ 7,527**	**$ 1,778**	**$ 1,843**	**$ 2,458**	**$ 2,658**	**$ 2,582**	**$ 77,366**	**312**
15	**FPS sub-total**	**$ 300**	**$ 410**	**$ 334**	**$ 423**	**$ 334**	**$ 361**	**$ 340**	**$ 357**	**$ 369**	**$ 393**	**$ 380**	**$ 340**	**$ 4,343**	**8**
16	**Short-term market sales sub-total**	**$ 12,066**	**$ 21,687**	**$ 36,055**	**$ 46,660**	**$ 48,851**	**$ 52,104**	**$ 32,600**	**$ 34,453**	**$ 36,479**	**$ 24,443**	**$ 8,619**	**$ 4,927**	**$ 358,943**	**1,153**
17	**Long Term Contractual Obligations sub-total**	**$ 27**	**$ 6,065**	**$ 6,231**	**$ 6,212**	**$ 5,701**	**$ 3,141**	**$ 3,043**	**$ 72**	**$ 46**	**$ 38**	**$ 31**	**$ 21**	**$ 30,626**	**108**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**-**
20	Miscellaneous Credits	$ 11	$ 9	$ 11	$ 1	$ 1	$ (3)	$ (2)	$ (1)	$ -	$ -	$ -	$ -	$ 27	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,181)	$ (3,181)	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,821)	$ (26,821)	-
23	**Other Sales sub-total**	**$ 11**	**$ 9**	**$ 11**	**$ 1**	**$ 1**	**$ (3)**	**$ (2)**	**$ (1)**	**$ -**	**$ -**	**$ -**	**$ (26,821)**	**$ (26,794)**	**-**
24	**Gross Sales**	**$189,182**	**$208,276**	**$241,708**	**$245,441**	**$244,804**	**$250,735**	**$236,341**	**$176,777**	**$189,365**	**$179,371**	**$176,798**	**$152,296**	**$2,487,914**	**8,716**
25	GTA Delivery charge	$ 135	$ 183	$ 197	$ 177	$ 164	$ 117	$ 135	$ 140	$ 140	$ 165	$ 150	$ 145	$ 1,847	-
26	Energy Efficiency Revenues	$ 614	$ 518	$ 1,037	$ 221	$ 299	$ 880	$ 939	$ 939	$ 939	$ 939	$ 939	$ 939	$ 9,200	-
27	Irrigation Pumping Power	$ 235	$ 233	$ 140	$ 58	$ 8	$ 3	$ 3	$ 3	$ 4	$ 37	$ 111	$ 155	$ 991	15
28	Reserve Energy	$ 702	$ 702	$ 702	$ 702	$ 702	$ 620	$ 702	$ 702	$ 702	$ 702	$ 702	$ 702	$ 8,342	162
29	Downstream Benefits	$ 546	$ 546	$ 546	$ 546	$ 546	$ 546	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,620	-
30	Upper Baker Revenues	$ -	$ 104	$ 108	$ 105	$ 106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 424	1
31	**Miscellaneous Revenues**	**$2,362**	**$2,419**	**$3,412**	**$2,068**	**$2,114**	**$2,473**	**$2,451**	**$2,456**	**$2,458**	**$2,516**	**$2,575**	**$2,613**	**$29,917**	**178**
32	Regulating Reserve	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 6,058	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,867	$ 4,867	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,173	$ 5,173	$ 5,173	$ 61,559	-
34	VERBS for Solar	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 15	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 1,592	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 202	-
37	Settlement Annual Budget Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Rounding Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Spinning	$ 1,541	$ 1,778	$ 1,977	$ 2,016	$ 1,831	$ 1,902	$ 2,073	$ 2,000	$ 2,072	$ 2,106	$ 1,968	$ 1,704	$ 22,967	-
42	Operating Reserve - Supplemental	$ 1,411	$ 1,629	$ 1,811	$ 1,847	$ 1,677	$ 1,742	$ 1,899	$ 1,832	$ 1,898	$ 1,930	$ 1,803	$ 1,561	$ 21,043	-
43	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,569	-
44	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 333	-
45	Energy Imbalance	$ 513	$ 738	$ 247	$ 247	$ 301	$ 100	$ 187	$ 175	$ 84	$ 116	$ (9)	$ (79)	$ 2,620	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ 419	$ 810	$ 1,042	$ 491	$ 625	$ 429	$ 176	$ 3,992	-
47	Redispatch	$ 2	$ -	$ 1	$ 3	$ 2	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 242	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 7,500	-
49	Station Service	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 2,385	9
50	Operating Reserve - Energy	$ 35	$ 102	$ 52	$ 34	$ 36	$ 86	$ 82	$ 61	$ 59	$ 124	$ 101	$ 96	$ 868	-
51	**Generation Inputs / Inter-business line**	**$ 10,006**	**$ 10,751**	**$ 10,913**	**$ 10,973**	**$ 10,671**	**$ 11,089**	**$ 11,891**	**$ 11,968**	**$ 11,462**	**$ 11,745**	**$ 11,137**	**$ 10,303**	**$ 132,908**	**9**
52	4(h)(10)(c)	$ 9,411	$ 8,456	$ 7,292	$ 6,365	$ 1,874	$ 5,608	$ 4,499	$ 5,672	$ 5,418	$ 5,497	$ 4,852	$ 8,754	$ 73,697	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 9,795**	**$ 8,839**	**$ 7,675**	**$ 6,748**	**$ 2,257**	**$ 5,992**	**$ 4,882**	**$ 6,055**	**$ 5,801**	**$ 5,880**	**$ 5,235**	**$ 9,137**	**$ 78,297**	**-**
55	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Balancing Power Purchase sub-total**	$ 112	$ 6,227	$ 2,674	$ (610)	$ (2,240)	$ 1,469	$ 6,176	$ 951	$ 2,090	$ 4,492	$ 5,822	$ 4,709	$ 31,870	189
57	**Other Power Purchase sub-total**	**$ 2,093**	**$ 2,025**	**$ 2,094**	**$ 2,094**	**$ 1,891**	**$ 2,091**	**$ 2,027**	**$ 2,094**	**$ 2,027**	**$ 2,094**	**$ 2,094**	**$ 2,027**	**$ 24,650**	**141**
58	**Power Purchases**	**$ 2,205**	**$ 8,252**	**$ 4,768**	**$ 1,485**	**$ (349)**	**$ 3,560**	**$ 8,202**	**$ 3,045**	**$ 4,117**	**$ 6,586**	**$ 7,916**	**$ 6,736**	**$ 56,521**	**330**
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Table 4.1 - Revenue at Current Rates

	B C D E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Table 4.1 - Revenue at Current Rates**													**2016**	
2	**Category**	**201510**	**201511**	**201512**	**201601**	**201602**	**201603**	**201604**	**201605**	**201606**	**201607**	**201608**	**201609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 192,324	$ 2,307,887	6,848
4	Non-Slice Revenue	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (21,548)	$ (258,576)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,907)	$ (9,027)	$ 16,892	$ 33,851	$ 23,831	$ 3,559	$ 6,415	$ (30,276)	$ (16,147)	$ (430)	$ (7,445)	$ 3,570	$ 20,886	(9)
7	Demand Revenue	$ 3,127	$ 2,052	$ 7,108	$ 5,633	$ 3,815	$ 4,741	$ 3,234	$ 1,622	$ 2,539	$ 3,083	$ 4,916	$ 3,811	$ 45,681	-
8	Irrigation Rate Discount	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (20,604)	-
9	Low Density Discount	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (3,192)	$ (38,300)	-
10	Tier 2	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 1,986	$ 23,833	68
11	RSS (Non-Federal)	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 1,329	-
12	**PF customers (TRM) sub-total**	**$ 167,185**	**$ 160,989**	**$ 191,964**	**$ 207,448**	**$ 195,610**	**$ 176,264**	**$ 177,613**	**$ 139,310**	**$ 154,356**	**$ 170,617**	**$ 165,436**	**$ 175,345**	**$ 2,082,137**	**6,908**
13	**NR sub-total**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 356**	**0**
14	**DSIs sub-total**	**$ 2,720**	**$ 2,881**	**$ 3,148**	**$ 3,044**	**$ 2,808**	**$ 2,579**	**$ 2,205**	**$ 1,868**	**$ 1,912**	**$ 2,560**	**$ 2,791**	**$ 2,690**	**$ 31,206**	**91**
15	**FPS sub-total**	**$ 235**	**$ 240**	**$ 260**	**$ 255**	**$ 245**	**$ 240**	**$ 235**	**$ 240**	**$ 245**	**$ 255**	**$ 240**	**$ 235**	**$ 2,920**	**8**
16	**Short-term market sales sub-total**	**$ 9,325**	**$ 14,938**	**$ 10,207**	**$ 30,109**	**$ 26,261**	**$ 28,947**	**$ 36,371**	**$ 58,017**	**$ 56,116**	**$ 44,339**	**$ 21,681**	**$ 6,782**	**$ 343,094**	**1,759**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 6,933**	**$ 7,129**	**$ 7,138**	**$ 6,506**	**$ 3,563**	**$ 3,476**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,102**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**119**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 3,877**	**-**
24	**Gross Sales**	**$179,825**	**$186,304**	**$213,030**	**$248,316**	**$231,754**	**$213,066**	**$220,223**	**$199,819**	**$213,029**	**$218,158**	**$190,542**	**$185,420**	**$2,499,487**	**8,975**
25	GTA Delivery charge	$ 360	$ 405	$ 510	$ 450	$ 455	$ 410	$ 345	$ 370	$ 390	$ 435	$ 400	$ 335	$ 4,865	-
26	Energy Efficiency Revenues	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 15,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 374	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,192	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 103	$ 117	$ 114	$ 117	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 457	1
31	**Miscellaneous Revenues**	**$2,996**	**$3,218**	**$3,381**	**$3,441**	**$3,404**	**$3,149**	**$3,002**	**$2,977**	**$2,992**	**$3,037**	**$3,001**	**$2,938**	**$37,541**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,246	$ 6,644	$ 9,118	$ 10,257	$ 8,370	$ 7,632	$ 6,894	$ 6,364	$ 7,074	$ 6,183	$ 5,868	$ 8,458	$ 91,107	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,629**	**$ 7,027**	**$ 9,502**	**$ 10,641**	**$ 8,753**	**$ 8,015**	**$ 7,277**	**$ 6,747**	**$ 7,457**	**$ 6,566**	**$ 6,252**	**$ 8,841**	**$ 95,707**	**-**
55	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Balancing Power Purchase sub-total**	$ 1,223	$ 1,654	$ 3,089	$ 2,609	$ 930	$ 161	$ 36	$ 19	$ 19	$ 246	$ 892	$ 3,753	$ 14,631	121
57	**Other Power Purchase sub-total**	**$ 1,868**	**$ 1,811**	**$ 1,868**	**$ 1,868**	**$ 1,748**	**$ 1,866**	**$ 1,808**	**$ 1,868**	**$ 1,808**	**$ 4,754**	**$ 4,859**	**$ 4,643**	**$ 30,769**	**60**
58	**Power Purchases**	**$ 3,091**	**$ 3,465**	**$ 4,957**	**$ 4,477**	**$ 2,678**	**$ 2,027**	**$ 1,844**	**$ 1,887**	**$ 1,827**	**$ 5,000**	**$ 5,751**	**$ 8,396**	**$ 45,400**	**181**
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Table 4.1 - Revenue at Current Rates

	B C D E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.1 - Revenue at Current Rates**													**2017**	
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 193,374	$ 2,320,485	6,886
4	Non-Slice Revenue	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (21,709)	$ (260,513)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,767)	$ (7,676)	$ 18,052	$ 35,432	$ 28,090	$ 4,124	$ 6,270	$ (30,285)	$ (16,387)	$ (359)	$ (7,255)	$ 4,106	$ 30,346	22
7	Demand Revenue	$ 2,667	$ 2,783	$ 7,256	$ 5,773	$ 3,541	$ 4,856	$ 2,802	$ 2,140	$ 2,587	$ 3,140	$ 5,015	$ 3,880	$ 46,440	-
8	Irrigation Rate Discount	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (1,717)	$ (20,604)	-
9	Low Density Discount	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (3,244)	$ (38,924)	-
10	Tier 2	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 2,307	$ 27,679	79
11	RSS (Non-Federal)	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 1,432	-
12	**PF customers (TRM) sub-total**	**$ 168,030**	**$ 164,237**	**$ 194,438**	**$ 210,335**	**$ 200,761**	**$ 178,110**	**$ 178,201**	**$ 140,985**	**$ 155,330**	**$ 171,911**	**$ 166,889**	**$ 177,115**	**$ 2,106,341**	**6,987**
13	**NR sub-total**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 356**	**0**
14	**DSIs sub-total**	**$ 2,720**	**$ 2,881**	**$ 3,148**	**$ 3,044**	**$ 2,712**	**$ 2,579**	**$ 2,205**	**$ 1,868**	**$ 1,912**	**$ 2,560**	**$ 2,791**	**$ 2,690**	**$ 31,110**	**91**
15	**FPS sub-total**	**$ 190**	**$ 195**	**$ 220**	**$ 210**	**$ 205**	**$ 200**	**$ 190**	**$ 195**	**$ 200**	**$ 210**	**$ 200**	**$ 190**	**$ 2,410**	**9**
16	**Short-term market sales sub-total**	**$ 13,107**	**$ 15,640**	**$ 11,222**	**$ 31,371**	**$ 27,082**	**$ 37,588**	**$ 36,991**	**$ 56,096**	**$ 53,455**	**$ 46,202**	**$ 24,396**	**$ 8,958**	**$ 362,109**	**1,703**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 6,933**	**$ 7,129**	**$ 7,138**	**$ 6,506**	**$ 3,563**	**$ 3,476**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,102**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**118**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
24	**Gross Sales**	**$184,086**	**$189,887**	**$216,157**	**$252,098**	**$237,266**	**$222,688**	**$221,063**	**$199,206**	**$210,974**	**$220,948**	**$194,349**	**$189,000**	**$2,537,721**	**8,997**
25	GTA Delivery charge	$ 360	$ 410	$ 510	$ 460	$ 460	$ 410	$ 350	$ 370	$ 390	$ 440	$ 400	$ 335	$ 4,895	-
26	Energy Efficiency Revenues	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 7,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 374	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,193	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 116	$ 121	$ 116	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 466	1
31	**Miscellaneous Revenues**	**$1,970**	**$2,160**	**$2,208**	**$2,326**	**$2,284**	**$2,072**	**$1,990**	**$1,940**	**$1,935**	**$1,935**	**$1,935**	**$1,936**	**$29,580**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 7,923	$ 5,922	$ 8,244	$ 10,262	$ 8,333	$ 7,294	$ 6,602	$ 6,016	$ 6,971	$ 5,914	$ 5,578	$ 8,725	$ 87,786	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,306**	**$ 6,305**	**$ 8,628**	**$ 10,646**	**$ 8,716**	**$ 7,678**	**$ 6,985**	**$ 6,400**	**$ 7,354**	**$ 6,298**	**$ 5,962**	**$ 9,108**	**$ 92,386**	**-**
55	**Augmentation Power Purchase sub-total**	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 20,947	81
56	**Balancing Power Purchase sub-total**	$ 1,801	$ 864	$ 3,350	$ 1,373	$ 1,267	$ 66	$ 129	$ 19	$ 19	$ 329	$ 1,331	$ 3,278	$ 13,823	113
57	**Other Power Purchase sub-total**	**$ 5,845**	**$ 5,661**	**$ 5,845**	**$ 5,828**	**$ 5,288**	**$ 5,854**	**$ 5,020**	**$ 5,196**	**$ 5,072**	**$ 5,143**	**$ 5,248**	**$ 5,020**	**$ 65,020**	**67**
58	**Power Purchases**	**$ 9,391**	**$ 8,270**	**$ 10,940**	**$ 8,946**	**$ 8,300**	**$ 7,666**	**$ 6,894**	**$ 6,960**	**$ 6,837**	**$ 7,217**	**$ 8,325**	**$ 10,043**	**$ 99,790**	**261**
59															
60															

Table 4.2 - Revenue at Proposed Rates

	B C D E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**Table 4.2 - Revenue at Proposed Rates**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 191,650	$ 191,650	$ 191,650	$ 191,650	$ 191,650	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 2,300,218	5,063
4	Non-Slice Revenue	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,442)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (257,365)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,862
6	Load Shaping Revenue	$ (3,835)	$ (6,636)	$ 7,224	$ 7,558	$ 7,874	$ 12,040	$ 20,571	$ (28,892)	$ (17,137)	$ (16,170)	$ (3,925)	$ 1,120	$ (20,208)	19
7	Demand Revenue	$ 1,443	$ 7,360	$ 11,820	$ 4,667	$ 3,163	$ 3,817	$ 3,325	$ 1,791	$ 2,342	$ 3,595	$ 3,772	$ 3,290	$ 50,386	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,900)	$ (4,335)	$ (4,992)	$ (4,097)	$ (2,492)	$ (18,816)	-
9	Low Density Discount	$ (2,622)	$ (2,710)	$ (3,105)	$ (2,824)	$ (2,726)	$ (3,011)	$ (3,363)	$ (2,258)	$ (2,541)	$ (2,721)	$ (2,931)	$ (2,879)	$ (33,691)	-
10	Tier 2	$ 2,186	$ 2,169	$ 2,186	$ 2,186	$ 1,964	$ 2,281	$ 2,210	$ 2,284	$ 2,210	$ 2,284	$ 2,284	$ 2,195	$ 26,439	75
11	RSS (Non-Federal)	$ 172	$ 50	$ 47	$ 111	$ 170	$ (51)	$ (48)	$ (54)	$ (50)	$ (52)	$ (53)	$ (50)	$ 191	-
12	**PF customers (TRM) sub-total**	**$ 167,551**	**$ 170,440**	**$ 188,380**	**$ 181,906**	**$ 180,653**	**$ 185,335**	**$ 192,955**	**$ 140,229**	**$ 150,749**	**$ 152,203**	**$ 165,309**	**$ 171,445**	**$ 2,043,973**	**7,019**
13	**NR sub-total**	**$ (56)**	**$ (106)**	**$ (110)**	**$ (159)**	**$ (153)**	**$ (155)**	**$ (122)**	**$ (110)**	**$ (120)**	**$ (163)**	**$ (198)**	**$ (198)**	**$ (1,649)**	**-**
14	**DSIs sub-total**	**$ 9,283**	**$ 9,770**	**$ 10,808**	**$ 10,397**	**$ 9,416**	**$ 8,845**	**$ 7,527**	**$ 1,778**	**$ 1,843**	**$ 2,458**	**$ 2,658**	**$ 2,582**	**$ 77,366**	**312**
15	**FPS sub-total**	**$ 300**	**$ 410**	**$ 334**	**$ 423**	**$ 334**	**$ 361**	**$ 340**	**$ 357**	**$ 369**	**$ 393**	**$ 380**	**$ 340**	**$ 4,343**	**8**
16	**Short-term market sales sub-total**	**$ 12,066**	**$ 21,687**	**$ 36,055**	**$ 46,660**	**$ 48,851**	**$ 52,104**	**$ 32,600**	**$ 34,453**	**$ 36,479**	**$ 24,443**	**$ 8,619**	**$ 4,927**	**$ 358,943**	**1,153**
17	**Long Term Contractual Obligations sub-total**	**$ 27**	**$ 6,065**	**$ 6,231**	**$ 6,212**	**$ 5,701**	**$ 3,141**	**$ 3,043**	**$ 72**	**$ 46**	**$ 38**	**$ 31**	**$ 21**	**$ 30,626**	**108**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**-**
20	Miscellaneous Credits	$ 11	$ 9	$ 11	$ 1	$ 1	$ (3)	$ (2)	$ (1)	$ -	$ -	$ -	$ -	$ 27	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,181)	$ (3,181)	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,821)	$ (26,821)	-
23	**Other Sales sub-total**	**$ 11**	**$ 9**	**$ 11**	**$ 1**	**$ 1**	**$ (3)**	**$ (2)**	**$ (1)**	**$ -**	**$ -**	**$ -**	**$ (26,821)**	**$ (26,794)**	**-**
24	**Gross Sales**	**$189,182**	**$208,276**	**$241,708**	**$245,441**	**$244,804**	**$250,735**	**$236,341**	**$176,777**	**$189,365**	**$179,371**	**$176,798**	**$152,296**	**$2,487,914**	**8,716**
25	GTA Delivery charge	$ 135	$ 183	$ 197	$ 177	$ 164	$ 117	$ 135	$ 140	$ 140	$ 165	$ 150	$ 145	$ 1,847	-
26	Energy Efficiency Revenues	$ 614	$ 518	$ 1,037	$ 221	$ 299	$ 880	$ 939	$ 939	$ 939	$ 939	$ 939	$ 939	$ 9,200	-
27	Irrigation Pumping Power	$ 235	$ 233	$ 140	$ 58	$ 8	$ 3	$ 3	$ 3	$ 4	$ 37	$ 111	$ 155	$ 991	15
28	Reserve Energy	$ 702	$ 702	$ 702	$ 702	$ 702	$ 620	$ 702	$ 702	$ 702	$ 702	$ 702	$ 702	$ 8,342	162
29	Downstream Benefits	$ 546	$ 546	$ 546	$ 546	$ 546	$ 546	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,620	-
30	Upper Baker Revenues	$ -	$ 104	$ 108	$ 105	$ 106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 424	1
31	**Miscellaneous Revenues**	**$2,246**	**$2,304**	**$3,297**	**$1,953**	**$1,999**	**$2,358**	**$2,336**	**$2,341**	**$2,343**	**$2,400**	**$2,460**	**$2,498**	**$29,917**	**178**
32	Regulating Reserve	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 6,058	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,867	$ 4,867	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,187	$ 5,173	$ 5,173	$ 5,173	$ 61,559	-
34	VERBS for Solar	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 15	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 1,592	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 202	-
37	Settlement Annual Budget Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Rounding Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Spinning	$ 1,541	$ 1,778	$ 1,977	$ 2,016	$ 1,831	$ 1,902	$ 2,073	$ 2,000	$ 2,072	$ 2,106	$ 1,968	$ 1,704	$ 22,967	-
42	Operating Reserve - Supplemental	$ 1,411	$ 1,629	$ 1,811	$ 1,847	$ 1,677	$ 1,742	$ 1,899	$ 1,832	$ 1,898	$ 1,930	$ 1,803	$ 1,561	$ 21,043	-
43	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,569	-
44	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 333	-
45	Energy Imbalance	$ 513	$ 738	$ 247	$ 247	$ 301	$ 100	$ 187	$ 175	$ 84	$ 116	$ (9)	$ (79)	$ 2,620	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ 419	$ 810	$ 1,042	$ 491	$ 625	$ 429	$ 176	$ 3,992	-
47	Redispatch	$ 2	$ -	$ 1	$ 3	$ 2	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 242	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 7,500	-
49	Station Service	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 2,385	9
50	Operating Reserve - Energy	$ 35	$ 102	$ 52	$ 34	$ 36	$ 86	$ 82	$ 61	$ 59	$ 124	$ 101	$ 96	$ 868	-
51	**Generation Inputs / Inter-business line**	**$ 10,006**	**$ 10,751**	**$ 10,913**	**$ 10,973**	**$ 10,671**	**$ 11,089**	**$ 11,891**	**$ 11,968**	**$ 11,462**	**$ 11,745**	**$ 11,137**	**$ 10,303**	**$ 132,908**	**9**
52	4(h)(10)(c)	$ 9,411	$ 8,456	$ 7,292	$ 6,365	$ 1,874	$ 5,608	$ 4,499	$ 5,672	$ 5,418	$ 5,497	$ 4,852	$ 8,754	$ 73,697	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 9,795**	**$ 8,839**	**$ 7,675**	**$ 6,748**	**$ 2,257**	**$ 5,992**	**$ 4,882**	**$ 6,055**	**$ 5,801**	**$ 5,880**	**$ 5,235**	**$ 9,137**	**$ 78,297**	**-**
55	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Balancing Power Purchase sub-total**	$ 112	$ 6,227	$ 2,674	$ (610)	$ (2,240)	$ 1,469	$ 6,176	$ 951	$ 2,090	$ 4,492	$ 5,822	$ 4,709	$ 31,870	189
57	**Other Power Purchase sub-total**	**$ 2,093**	**$ 2,025**	**$ 2,094**	**$ 2,094**	**$ 1,891**	**$ 2,091**	**$ 2,027**	**$ 2,094**	**$ 2,027**	**$ 2,094**	**$ 2,094**	**$ 2,027**	**$ 24,650**	**141**
58	**Power Purchases**	**$ 2,205**	**$ 8,252**	**$ 4,768**	**$ 1,485**	**$ (349)**	**$ 3,560**	**$ 8,202**	**$ 3,045**	**$ 4,117**	**$ 6,586**	**$ 7,916**	**$ 6,736**	**$ 56,521**	**330**

Table 4.2 - Revenue at Proposed Rates

	B C D E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Table 4.2 - Revenue at Proposed Rates**													**2016**	
2	**Category**	**201510**	**201511**	**201512**	**201601**	**201602**	**201603**	**201604**	**201605**	**201606**	**201607**	**201608**	**201609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 202,299	$ 2,427,590	6,848
4	Non-Slice Revenue	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (21,911)	$ (262,935)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,473)	$ (7,335)	$ 12,634	$ 27,298	$ 19,187	$ 3,123	$ 6,429	$ (33,114)	$ (16,850)	$ (516)	$ (6,613)	$ 3,272	$ 4,040	(9)
7	Demand Revenue	$ 3,358	$ 2,007	$ 6,513	$ 5,441	$ 3,731	$ 4,847	$ 3,723	$ 2,080	$ 3,148	$ 3,377	$ 5,343	$ 4,379	$ 47,946	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (3,109)	$ (2,885)	$ (3,639)	$ (3,835)	$ (3,613)	$ (3,191)	$ (3,392)	$ (2,523)	$ (3,088)	$ (3,591)	$ (3,532)	$ (3,467)	$ (39,865)	-
10	Tier 2	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 1,905	$ 22,866	68
11	RSS (Non-Federal)	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,172	-
12	**PF customers (TRM) sub-total**	**$ 179,168**	**$ 174,178**	**$ 197,899**	**$ 211,295**	**$ 201,696**	**$ 187,169**	**$ 189,151**	**$ 145,421**	**$ 160,498**	**$ 175,786**	**$ 172,767**	**$ 183,641**	**$ 2,178,668**	**6,908**
13	**NR sub-total**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 356**	**0**
14	**DSIs sub-total**	**$ 2,902**	**$ 2,847**	**$ 2,965**	**$ 3,013**	**$ 2,790**	**$ 2,736**	**$ 2,598**	**$ 2,474**	**$ 2,418**	**$ 2,788**	**$ 3,003**	**$ 2,974**	**$ 33,509**	**91**
15	**FPS sub-total**	**$ 235**	**$ 240**	**$ 260**	**$ 255**	**$ 245**	**$ 240**	**$ 235**	**$ 240**	**$ 245**	**$ 255**	**$ 240**	**$ 235**	**$ 2,921**	**8**
16	**Short-term market sales sub-total**	**$ 9,325**	**$ 14,938**	**$ 10,207**	**$ 30,109**	**$ 26,261**	**$ 28,947**	**$ 36,371**	**$ 58,017**	**$ 56,116**	**$ 44,339**	**$ 21,681**	**$ 6,782**	**$ 343,094**	**1,762**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 6,933**	**$ 7,129**	**$ 7,138**	**$ 6,506**	**$ 3,563**	**$ 3,476**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,102**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**	**$ -**	**119**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**	**$ 1,151**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
23	**Other Sales sub-total**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 3,877**	**-**
24	**Gross Sales**	**$191,990**	**$199,459**	**$218,782**	**$252,133**	**$237,821**	**$224,129**	**$232,154**	**$206,536**	**$219,677**	**$223,555**	**$198,085**	**$194,000**	**$2,598,678**	**8,978**
25	GTA Delivery charge	$ 360	$ 405	$ 510	$ 450	$ 455	$ 410	$ 345	$ 370	$ 390	$ 435	$ 400	$ 335	$ 4,865	-
26	Energy Efficiency Revenues	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 15,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 374	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,192	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 103	$ 117	$ 114	$ 117	$ 5	$ -	$ -	$ -	$ -	$ -	-	$ 457	1
31	**Miscellaneous Revenues**	**$2,996**	**$3,218**	**$3,381**	**$3,441**	**$3,404**	**$3,154**	**$3,002**	**$2,977**	**$2,992**	**$3,037**	**$3,001**	**$2,938**	**$37,541**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,246	$ 6,644	$ 9,118	$ 10,257	$ 8,370	$ 7,632	$ 6,894	$ 6,364	$ 7,074	$ 6,183	$ 5,868	$ 8,458	$ 91,107	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,629**	**$ 7,027**	**$ 9,502**	**$ 10,641**	**$ 8,753**	**$ 8,015**	**$ 7,277**	**$ 6,747**	**$ 7,457**	**$ 6,566**	**$ 6,252**	**$ 8,841**	**$ 95,707**	**-**
55	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-	$ -	-
56	**Balancing Power Purchase sub-total**	$ 1,223	$ 1,654	$ 3,089	$ 2,609	$ 930	$ 161	$ 36	$ 19	$ 19	$ 246	$ 892	$ 3,753	$ 14,631	121
57	**Other Power Purchase sub-total**	**$ 1,868**	**$ 1,811**	**$ 1,868**	**$ 1,868**	**$ 1,748**	**$ 1,866**	**$ 1,808**	**$ 1,868**	**$ 1,808**	**$ 4,754**	**$ 4,859**	**$ 4,643**	**$ 30,769**	**60**
58	**Power Purchases**	**$ 3,091**	**$ 3,465**	**$ 4,957**	**$ 4,477**	**$ 2,678**	**$ 2,027**	**$ 1,844**	**$ 1,887**	**$ 1,827**	**$ 5,000**	**$ 5,751**	**$ 8,396**	**$ 45,400**	**181**

Table 4.2 - Revenue at Proposed Rates

	B C D E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.2 - Revenue at Proposed Rates**													**2017**	
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 203,403	$ 2,440,841	6,886
4	Non-Slice Revenue	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (264,905)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,371)	$ (6,226)	$ 13,503	$ 28,569	$ 22,614	$ 3,606	$ 6,385	$ (33,289)	$ (17,103)	$ (453)	$ (6,443)	$ 3,773	$ 11,564	22
7	Demand Revenue	$ 2,864	$ 2,722	$ 6,649	$ 5,577	$ 3,463	$ 4,965	$ 3,225	$ 2,744	$ 3,207	$ 3,440	$ 5,450	$ 4,457	$ 48,763	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (3,131)	$ (2,979)	$ (3,688)	$ (3,891)	$ (3,689)	$ (3,234)	$ (3,404)	$ (2,583)	$ (3,132)	$ (3,642)	$ (3,578)	$ (3,515)	$ (40,464)	-
10	Tier 2	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 2,292	$ 27,509	79
11	RSS (Non-Federal)	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 1,679	-
12	**PF customers (TRM) sub-total**	**$ 180,123**	**$ 177,277**	**$ 200,225**	**$ 214,015**	**$ 206,149**	**$ 189,096**	**$ 189,967**	**$ 147,219**	**$ 161,630**	**$ 177,230**	**$ 174,368**	**$ 185,542**	**$ 2,202,841**	**6,987**
13	**NR sub-total**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 30**	**$ 356**	**0**
14	**DSIs sub-total**	**$ 2,902**	**$ 2,847**	**$ 2,965**	**$ 3,013**	**$ 2,694**	**$ 2,736**	**$ 2,598**	**$ 2,474**	**$ 2,418**	**$ 2,788**	**$ 3,003**	**$ 2,974**	**$ 33,413**	**91**
15	**FPS sub-total**	**$ 190**	**$ 195**	**$ 220**	**$ 210**	**$ 205**	**$ 200**	**$ 190**	**$ 195**	**$ 200**	**$ 211**	**$ 200**	**$ 190**	**$ 2,411**	**9**
16	**Short-term market sales sub-total**	**$ 13,107**	**$ 15,640**	**$ 11,222**	**$ 31,371**	**$ 27,082**	**$ 37,588**	**$ 36,991**	**$ 56,096**	**$ 53,455**	**$ 46,202**	**$ 24,396**	**$ 8,958**	**$ 362,109**	**1,711**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 6,933**	**$ 7,129**	**$ 7,138**	**$ 6,506**	**$ 3,563**	**$ 3,476**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,102**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**118**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
24	**Gross Sales**	**$196,361**	**$202,893**	**$221,761**	**$255,748**	**$242,636**	**$233,832**	**$233,222**	**$206,046**	**$217,780**	**$226,495**	**$202,039**	**$197,711**	**$2,636,880**	**9,006**
25	GTA Delivery charge	$ 360	$ 410	$ 510	$ 460	$ 460	$ 410	$ 350	$ 370	$ 390	$ 440	$ 400	$ 335	$ 4,895	-
26	Energy Efficiency Revenues	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 7,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 374	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,193	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 110	$ 121	$ 116	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 466	1
31	**Miscellaneous Revenues**	**$2,330**	**$2,564**	**$2,718**	**$2,786**	**$2,744**	**$2,482**	**$2,340**	**$2,310**	**$2,325**	**$2,375**	**$2,335**	**$2,271**	**$29,580**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 7,923	$ 5,922	$ 8,244	$ 10,262	$ 8,333	$ 7,294	$ 6,602	$ 6,016	$ 6,971	$ 5,914	$ 5,578	$ 8,725	$ 87,786	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,306**	**$ 6,305**	**$ 8,628**	**$ 10,646**	**$ 8,716**	**$ 7,678**	**$ 6,985**	**$ 6,400**	**$ 7,354**	**$ 6,298**	**$ 5,962**	**$ 9,108**	**$ 92,386**	**-**
55	**Augmentation Power Purchase sub-total**	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 1,746	$ 20,947	81
56	**Balancing Power Purchase sub-total**	$ 1,801	$ 864	$ 3,350	$ 1,373	$ 1,267	$ 66	$ 129	$ 19	$ 19	$ 329	$ 1,331	$ 3,278	$ 13,823	113
57	**Other Power Purchase sub-total**	**$ 5,845**	**$ 5,661**	**$ 5,845**	**$ 5,828**	**$ 5,288**	**$ 5,854**	**$ 5,020**	**$ 5,196**	**$ 5,072**	**$ 5,143**	**$ 5,248**	**$ 5,020**	**$ 65,020**	**67**
58	**Power Purchases**	**$ 9,391**	**$ 8,270**	**$ 10,940**	**$ 8,946**	**$ 8,300**	**$ 7,666**	**$ 6,894**	**$ 6,960**	**$ 6,837**	**$ 7,217**	**$ 8,325**	**$ 10,043**	**$ 99,790**	**261**

Table 4.3 – Composite and Non-slice revenue – FY 2016-2017

	A	B	C	D	E	F	G
1	**Table 4.3 – Composite and Non-slice revenue – FY 2016-2017**						
2	Table shows calculation of CHWM revenues at proposed rates.						
3							
4	**Billing Determinants**	**FY 2016**		**FY 2017**		**Rate Period**	
5	**TOCA...**	98.071770	A)	98.607100	A)	98.339435	
6	**Non-slice TOCA...**	71.453120	B)	71.988450	B)	71.720785	
7	**Slice Percentage...**	26.618650		26.618650		26.618650	
8							
9	**Annual TRM Rates ($000)**	**FY 2016**		**FY 2017**		**Rate Period**	
10	**Composite...**	$ 24,377		$ 25,127		$ 24,753	C)
11	**Non-Slice..**	$ (3,748)		$ (3,612)		$ (3,680)	D)
12	**Slice...**	$ -		$ -		$ -	
13							
14	**Yearly Revenues (Yearly TOCA * Rate Period rate)**	**FY 2016**		**FY 2017**			
15	**Composite (A * C)...**	$ 2,427,590	E)	$ 2,440,841	E)		
16	**Non-Slice (B * D)...**	$ (262,935)	E)	$ (264,905)	E)		
17	**Slice...**	$ -		$ -			
18							
19	**Monthly Revenues (Yearly Revenues / 12)**	**FY 2016**		**FY 2017**			
20	**Composite (E / 12)...**	$ 202,299		$ 203,403			
21	**Non-Slice (E / 12)..**	$ (21,911)		$ (22,075)			
22	**Slice...**	$ -		$ -			
23							
24	*Ties to Table 4.2, Revenue at Proposed Rates, lines 3-4*						

Table 4.4 – Load Shaping and Demand revenue – FY 2016-2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.4 – Load Shaping and Demand revenue – FY 2016-2017**														
2	Table shows calculation of CHWM revenues at proposed rates.														
3															
4															
5	**FY 2016**		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Total**
6	Load Shaping HLH (MWh)	A)	(178,014)	(371,422)	129,525	395,325	325,301	5,984	108,191	(1,234,546)	(596,155)	(239,573)	(316,622)	(21,761)	
7	Load Shaping LLH (MWh)	B)	62,593	133,683	356,520	616,487	386,614	134,601	180,294	(332,608)	(178,226)	280,598	122,097	154,201	
8	Load Shaping HLH Rate ($/MWh)	C)	$ 27.86	$ 28.56	$ 29.22	$ 30.02	$ 29.65	$ 25.38	$ 24.36	$ 22.10	$ 23.15	$ 27.43	$ 30.30	$ 31.75	
9	Load Shaping LLH Rate ($/MWh)	D)	$ 23.75	$ 24.48	$ 24.82	$ 25.03	$ 24.68	$ 22.07	$ 21.04	$ 17.53	$ 17.11	$ 21.58	$ 24.41	$ 25.70	
10	Load Shaping Revenue (A * C) + (B * D)		$ (3,472,883)	$ (7,335,235)	$ 12,633,557	$ 27,298,317	$ 19,186,832	$ 3,122,525	$ 6,428,911	$ (33,114,082)	$ (16,850,423)	$ (516,193)	$ (6,613,254)	$ 3,272,049	$ 4,040,119
11															
12	Demand (kW)	E)	335,172	195,455	619,669	504,258	350,009	530,868	424,961	261,665	377,878	342,157	490,169	383,408	
13	Demand Rate ($/kW-mo.)	F)	$ 10.02	$ 10.27	$ 10.51	$ 10.79	$ 10.66	$ 9.13	$ 8.76	$ 7.95	$ 8.33	$ 9.87	$ 10.90	$ 11.42	
14	Demand Revenue (E * F)		$ 3,358,420	$ 2,007,324	$ 6,512,724	$ 5,440,946	$ 3,731,097	$ 4,846,827	$ 3,722,654	$ 2,080,238	$ 3,147,724	$ 3,377,094	$ 5,342,837	$ 4,378,521	$ 47,946,406
15															
16															
17															
18															
19	**FY 2017**		**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Total**
20	Load Shaping HLH (MWh)	A)	(215,558)	(300,822)	146,349	419,079	398,075	17,183	66,304	(1,207,536)	(604,204)	(239,767)	(314,151)	(12,719)	
21	Load Shaping LLH (MWh)	B)	110,924	96,628	371,746	638,757	438,067	143,607	226,717	(376,647)	(182,119)	283,752	126,014	162,515	
22	Load Shaping HLH Rate ($/MWh)	C)	$ 27.86	$ 28.56	$ 29.22	$ 30.02	$ 29.65	$ 25.38	$ 24.36	$ 22.10	$ 23.15	$ 27.43	$ 30.30	$ 31.75	
23	Load Shaping LLH Rate ($/MWh)	D)	$ 23.75	$ 24.48	$ 24.82	$ 25.03	$ 24.68	$ 22.07	$ 21.04	$ 17.53	$ 17.11	$ 21.58	$ 24.41	$ 25.70	
24	Load Shaping Revenue (A * C) + (B * D)		$ (3,371,004)	$ (6,226,007)	$ 13,503,053	$ 28,568,839	$ 22,614,424	$ 3,605,526	$ 6,385,285	$ (33,289,170)	$ (17,103,369)	$ (453,441)	$ (6,442,788)	$ 3,772,795	$ 11,564,144
25															
26	Demand (kW)	E)	285,874	265,044	632,612	516,843	324,874	543,772	368,143	345,184	384,980	348,539	499,957	390,295	
27	Demand Rate ($/kW-mo.)	F)	$ 10.02	$ 10.27	$ 10.51	$ 10.79	$ 10.66	$ 9.13	$ 8.76	$ 7.95	$ 8.33	$ 9.87	$ 10.90	$ 11.42	
28	Demand Revenue (E * F)		$ 2,864,455	$ 2,722,000	$ 6,648,752	$ 5,576,732	$ 3,463,160	$ 4,964,634	$ 3,224,930	$ 2,744,211	$ 3,206,884	$ 3,440,078	$ 5,449,535	$ 4,457,170	$ 48,762,542
29															
30	*Ties to Table 4.2, Revenue at Proposed Rates, lines 6-7*														

Table 4.5 – Irrigation Rate Discount (IRD) – FY 2016-2017

	A	B	C	D	E	F	G	H
1	**Table 4.5 – Irrigation Rate Discount (IRD) – FY 2016-2017**							
2	Table shows calculation of IRD credit at proposed rates.							
3								
4	**Irrigation Rate Discount**							
5	**IRD Percentage**	37.06%						
6	**Total Irrigation Load (MWh)**	1,881,605						
7	**RT1SC**	6,983						
8	**Annual NonSlice Dollar Amount**	$ 2,195,483						
9	**Average Hours in Rate Period**	8772						
10	**Implied Discount ($/MWh)**	**11.77**	A)					
11								
12								
13								
14	**FY 2016**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**		**TOTAL**
15	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
16	IRD credit ($) (A * B)	$ (3,413,784)	$ (5,101,867)	$ (5,875,707)	$ (4,821,805)	$ (2,933,323)		**$ (22,146,485)**
17								
18								
19	**FY2017**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**		**TOTAL**
20	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
21	IRD credit ($) (A * B)	$ (3,413,784)	$ (5,101,867)	$ (5,875,707)	$ (4,821,805)	$ (2,933,323)		**$ (22,146,485)**
22								
23								
24	*Ties to Table 4.2, Revenue at Proposed Rates, line 8*							
25								

Table 4.6 – Low Density Discount (LDD) – FY 2016-2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1						**Table 4.6 – Low Density Discount (LDD) – FY 2016-2017**									
2						Table shows calculation of LDD credit at proposed rates.									
3															
4	Low Density Discount														
5	Customer Charge LDD	**FY 2016**	**FY 2017**												
6	TOCA LDD Offset %..	1.67%	1.69%	**A)**											
7															
8	TRM Costs after Adjustments														
9	Composite..	$ 2,427,590	$ 2,440,841												
10	Non-Slice..	$ (262,935)	$ (264,905)												
11	Slice..	$ -	$ -												
12		$ 2,164,656	$ 2,175,937	**B)**											
13															
14	LDD discount - Composite portion (A * B)......................	$ 36,215	$ 36,723	**C)**											
15	LDD discount (Demand/Load Shaping portion)................	$ 3,651	$ 3,741	**D) below**											
16	**Total LDD discount (C + D)..**	**$ 39,865**	**$ 40,464**												
17															
18	**Demand and Load Shaping Discount Detail**														
19	**FY 2016**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**		
20	Demand BD (kW)	16,127	9,847	29,019	21,265	15,683	21,343	19,498	11,102	18,851	15,413	21,863	15,038		
21	Load Shaping BD HLH (MWh)	(3,340)	(8,634)	4,027	9,597	7,595	(1,869)	4,342	(22,493)	(4,573)	5,571	2,346	4,222		
22	Load Shaping BD LLH (MWh)	938	515	7,977	11,976	8,227	1,165	4,636	(4,912)	1,133	12,421	8,382	5,594		
23	Demand Rate	$ 10.02	$ 10.27	$ 10.51	$ 10.79	$ 10.66	$ 9.13	$ 8.76	$ 7.95	$ 8.33	$ 9.87	$ 10.90	$ 11.42		
24	Load Shaping Rate (HLH)	$ 27.86	$ 28.56	$ 29.22	$ 30.02	$ 29.65	$ 25.38	$ 24.36	$ 22.10	$ 23.15	$ 27.43	$ 30.30	$ 31.75		
25	Load Shaping Rate (LLH)	$ 23.75	$ 24.48	$ 24.82	$ 25.03	$ 24.68	$ 22.07	$ 21.04	$ 17.53	$ 17.11	$ 21.58	$ 24.41	$ 25.70		
26	LDD credit (Demand/Load Shaping portion)	$ 90,822	$ (132,847)	$ 620,682	$ 817,288	$ 595,452	$ 173,138	$ 374,090	$ (494,940)	$ 70,525	$ 572,934	$ 513,997	$ 449,548	$ 3,650,691	
27														$ 3,650.69	**D)**
28	**FY 2017**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**		
29	Demand BD (kW)	13,480	13,889	29,515	22,125	12,708	21,495	16,048	14,702	19,216	15,987	21,948	15,249		
30	Load Shaping BD HLH (MWh)	(3,488)	(8,078)	4,038	9,540	9,124	(1,768)	4,032	(22,596)	(4,634)	5,533	2,479	4,271		
31	Load Shaping BD LLH (MWh)	1,362	275	8,018	12,226	9,016	1,035	4,966	(5,411)	1,102	12,601	8,313	5,630		
32	Demand Rate	$ 10.02	$ 10.27	$ 10.51	$ 10.79	$ 10.66	$ 9.13	$ 8.76	$ 7.95	$ 8.33	$ 9.87	$ 10.90	$ 11.42		
33	Load Shaping Rate (HLH)	$ 27.86	$ 28.56	$ 29.22	$ 30.02	$ 29.65	$ 25.38	$ 24.36	$ 22.10	$ 23.15	$ 27.43	$ 30.30	$ 31.75		
34	Load Shaping Rate (LLH)	$ 23.75	$ 24.48	$ 24.82	$ 25.03	$ 24.68	$ 22.07	$ 21.04	$ 17.53	$ 17.11	$ 21.58	$ 24.41	$ 25.70		
35	LDD credit(Demand/Load Shaping portion)	$ 70,255	$ (81,352)	$ 627,242	$ 831,117	$ 628,539	$ 174,223	$ 343,246	$ (477,319)	$ 71,617	$ 581,447	$ 517,275	$ 454,418	$ 3,740,707	
36														$ 3,740.71	**D)**
37	**LDD credit is negative revenue*														
38	*Ties to Table 4.2, Revenue at Proposed Rates, line 9*														

Table 4.7 – Tier 2 revenue – FY 2016-2017

	A	B	C
1	**Fiscal Year**		
2	**Rate Period**	**FY2016**	**FY2017**
3			
4	Base Power Purchase Cost	$ -	$ -
5	Rate Design Components	$ 114,165	$ 112,346
6	Other Costs	$ -	$ -
7	Rate $/MWh	**$ 29.72**	**$ 32.01**
8	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (102,425)	$ (101,278)
9	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
10	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,740)	$ (11,067)
11	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
12	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
13	Total ShortTerm Rate Revenue	$ 2,408,022	$ 2,444,874
14	Remarketing Credit	$ -	$ -
15	Remarketing Charge	$ -	$ -
16	Forecast Power Purchase Costs	$ -	$ -
17			
18			
19	Base Power Purchase Cost	$ 1,865,282	$ 2,045,460
20	Rate Design Components	$ 12,971	$ 14,406
21	Other Costs	$ -	$ -
22	Rate $/MWh	**$ 45.18**	**$ 49.60**
23	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (11,637)	$ (12,986)
24	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,334)	$ (1,419)
26	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
27	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
28	Total LoadGrowth Rate Revenue	$ 415,910	$ 485,767
29	Remarketing Credit	$ -	$ -
30	Remarketing Charge	$ 516,489	$ 575,371
31	Forecast Power Purchase Costs	$ -	$ -
32			
33	Base Power Purchase Cost	$ 17,160,598	$ 18,818,232
34	Rate Design Components	$ 569,340	$ 592,717
35	Other Costs	$ -	$ -
36	Rate $/MWh	**$ 44.72**	**$ 49.08**
37	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (510,791)	$ (534,328)
38	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
39	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (58,549)	$ (58,389)
40	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
41	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
42	Total Vintage.1 Rate Revenue	$ 18,069,742	$ 19,777,277
43	Remarketing Credit	$ 1,909,138	$ 2,145,775
44	Remarketing Charge	$ -	$ -
45	Forecast Power Purchase Costs	$ -	$ -
46			
47	Base Power Purchase Cost	$ 3,031,798	$ 5,718,528
48	Rate Design Components	$ 111,393	$ 206,162
49	Other Costs	$ -	$ -
50	Rate $/MWh	**$ 40.60**	**$ 43.18**
51	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (99,937)	$ (185,853)
52	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
53	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,455)	$ (20,309)
54	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
55	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
56	Total Vintage.1 Rate Revenue	$ 3,209,674	$ 6,052,109
57	Remarketing Credit	$ 965,186	$ 1,330,772
58	Remarketing Charge	$ -	$ -
59	Forecast Power Purchase Costs	$ -	$ -
60			
61			
62	Total Tier 2 Revenue Collection Before Remarking Charge/Credit	$ 24,103,348	$ 28,760,026
63	Total Tier 2 Remarketing Charge	$ 516,489	$ 575,371
64	Total Tier 2 Remarketing Credit	$ (2,874,323)	$ (3,476,547)
65	Non-Federal Remarketing Credit	$ (1,119,622)	$ (650,704)
66	Value of BPA Purchased Remarketing	$ 2,239,740	$ 2,301,031
67	**Total Tier 2 Revenue Collection**	**$ 22,865,632**	**$ 27,509,176**

Table 4.8 – Direct Service Industries (DSI) revenues – FY 2015-2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.8 – Direct Service Industries (DSI) revenues – FY 2015-2017**														
2	Table shows calculation of DSI revenues at current and proposed rates.														
3															
4	**FY 2015**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
5	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
6	LLH rate (per MWh)	B)	37.56	41.4	43.4	40.8	40.73	35.23	30.25	23.21	24.7	34.63	37.22	38.03	
7	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
8															
9	HLH consumption (MWh)	D)	134,766	118,836	129,905	129,722	121,239	129,942	129,792	34,800	36,192	36,192	36,192	34,800	1,072,378
10	LLH consumption (MWh)	E)	97,470	104,626	102,452	102,444	90,969	102,191	94,848	29,928	26,448	28,536	28,536	27,840	836,288
11	Demand (kW)	F)	-	885.00	-	-	1,042.64	-	-	-	-	-	-	-	1,928
12															
13	HLH revenues (A * D)	G)	5,622,438	5,429,617	6,361,448	6,217,575	5,700,658	5,244,470	4,658,235	1,083,324	1,189,269	1,470,119	1,595,705	1,523,544	46,096,402
14	LLH revenues (B * E)	H)	3,660,973	4,331,516	4,446,417	4,179,715	3,705,167	3,600,189	2,869,152	694,629	653,266	988,202	1,062,110	1,058,755	31,250,091
15	Demand revenues (C * F)	I)	-	9,293	-	-	10,343	-	-	-	-	-	-	-	19,636
16	TOTAL forecast revenues (G + H + I)	J)	$ 9,283,411	$ 9,770,426	$ 10,807,865	$ 10,397,291	$ 9,416,168	$ 8,844,659	$ 7,527,387	$ 1,777,953	$ 1,842,535	$ 2,458,321	$ 2,657,815	$ 2,582,299	$ 77,366,129
17															
18															
19	**FY 2016 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
20	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
21	LLH rate (per MWh)	B)	37.56	41.40	43.40	40.80	40.73	35.23	30.25	23.21	24.70	34.63	37.22	38.03	
22	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
23															
24	HLH consumption (MWh)	D)	39,227	36,416	36,125	37,749	36,180	37,972	37,854	37,624	36,472	37,156	39,368	34,693	446,836
25	LLH consumption (MWh)	E)	28,841	29,407	31,765	30,258	27,186	29,694	27,996	30,015	28,897	30,343	28,363	30,786	353,550
26	Demand (kW)	F)													
27															
28	HLH revenues (A * D)	G)	1,636,549	1,663,830	1,769,065	1,809,321	1,701,181	1,532,568	1,358,580	1,171,233	1,198,472	1,509,279	1,735,719	1,518,857	18,604,654
29	LLH revenues (B * E)	H)	1,083,286	1,217,433	1,378,594	1,234,533	1,107,271	1,046,115	846,865	696,642	713,755	1,050,768	1,055,689	1,170,798	12,601,749
30	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	TOTAL revenues (G + H + I)		$ 2,719,835	$ 2,881,263	$ 3,147,660	$ 3,043,854	$ 2,808,452	$ 2,578,683	$ 2,205,445	$ 1,867,875	$ 1,912,227	$ 2,560,047	$ 2,791,408	$ 2,689,655	$ 31,206,404
32															
33	**FY 2017 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
34	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
35	LLH rate (per MWh)	B)	37.56	41.40	43.40	40.80	40.73	35.23	30.25	23.21	24.70	34.63	37.22	38.03	
36	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
37															
38	HLH consumption (MWh)	D)	39,227	36,416	36,125	37,749	34,932	37,972	37,854	37,624	36,472	37,156	39,368	34,693	445,589
39	LLH consumption (MWh)	E)	28,841	29,407	31,765	30,258	26,248	29,694	27,996	30,015	28,897	30,343	28,363	30,786	352,613
40	Demand (kW)	F)													
41															
42	HLH revenues (A * D)	G)	1,636,549	1,663,830	1,769,065	1,809,321	1,642,520	1,532,568	1,358,580	1,171,233	1,198,472	1,509,279	1,735,719	1,518,857	18,545,993
43	LLH revenues (B * E)	H)	1,083,286	1,217,433	1,378,594	1,234,533	1,069,089	1,046,115	846,865	696,642	713,755	1,050,768	1,055,689	1,170,798	12,563,568
44	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
45	TOTAL revenues (G + H + I)		$ 2,719,835	$ 2,881,263	$ 3,147,660	$ 3,043,854	$ 2,711,609	$ 2,578,683	$ 2,205,445	$ 1,867,875	$ 1,912,227	$ 2,560,047	$ 2,791,408	$ 2,689,655	$ 31,109,561
46															
47	**FY 2016 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
48	HLH rate (per MWh)	A)	44.37	45.07	45.73	46.53	46.16	41.89	40.87	38.61	39.66	43.94	46.81	48.26	
49	LLH rate (per MWh)	B)	40.26	40.99	41.33	41.54	41.19	38.58	37.55	34.04	33.62	38.09	40.92	42.21	
50	Demand rate (kw/Mo)	C)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.9	11.42	
51															
52	HLH consumption (MWh)	D)	39,227	36,416	36,125	37,749	36,180	37,972	37,854	37,624	36,472	37,156	39,368	34,693	446,836
53	LLH consumption (MWh)	E)	28,841	29,407	31,765	30,258	27,186	29,694	27,996	30,015	28,897	30,343	28,363	30,786	353,550
54															
55															
56	HLH revenues (A * D)	G)	1,740,500	1,641,253	1,652,019	1,756,472	1,670,066	1,590,666	1,547,093	1,452,660	1,446,482	1,632,637	1,842,799	1,674,281	19,646,928
57	LLH revenues (B * E)	H)	1,161,158	1,205,376	1,312,841	1,256,924	1,119,776	1,145,590	1,051,233	1,021,701	971,516	1,155,754	1,160,634	1,299,484	13,861,987
58	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
59	TOTAL revenues (G + H + I)		$ 2,901,658	$ 2,846,629	$ 2,964,860	$ 3,013,396	$ 2,789,843	$ 2,736,256	$ 2,598,326	$ 2,474,361	$ 2,417,998	$ 2,788,391	$ 3,003,433	$ 2,973,765	$ 33,508,915
60															
61	**FY 2017 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
62	HLH rate (per MWh)	A)	44.37	45.07	45.73	46.53	46.16	41.89	40.87	38.61	39.66	43.94	46.81	48.26	
63	LLH rate (per MWh)	B)	40.26	40.99	41.33	41.54	41.19	38.58	37.55	34.04	33.62	38.09	40.92	42.21	
64	Demand rate (kw/Mo)	C)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.9	11.42	
65															
66	HLH consumption (MWh)	D)	39,227	36,416	36,125	37,749	34,932	37,972	37,854	37,624	36,472	37,156	39,368	34,693	445,589
67	LLH consumption (MWh)	E)	28,841	29,407	31,765	30,258	26,248	29,694	27,996	30,015	28,897	30,343	28,363	30,786	352,613
68															
69															
70	HLH revenues (A * D)	G)	1,740,500	1,641,253	1,652,019	1,756,472	1,612,478	1,590,666	1,547,093	1,452,660	1,446,482	1,632,637	1,842,799	1,674,281	19,589,340
71	LLH revenues (B * E)	H)	1,161,158	1,205,376	1,312,841	1,256,924	1,081,163	1,145,590	1,051,233	1,021,701	971,516	1,155,754	1,160,634	1,299,484	13,823,374
72	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
73	TOTAL revenues (G + H + I)		$ 2,901,658	$ 2,846,629	$ 2,964,860	$ 3,013,396	$ 2,693,641	$ 2,736,256	$ 2,598,326	$ 2,474,361	$ 2,417,998	$ 2,788,391	$ 3,003,433	$ 2,973,765	$ 33,412,714
74															
75															
76	*Ties to Table 4.1, Revenue at Current Rates, and 4.2, Revenue at Proposed Rates, line 14*														

SECTION 5: RATE SCHEDULES

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SECTION 6: GENERAL RATE SCHEDULE PROVISIONS

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SECTION 7: SLICE

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SECTION 8: AVERAGE SYSTEM COSTS

Table Descriptions

Table 8.1 IOUs Residential Loads and COUs Forecast Exchange Loads (MWh)
Table lists the monthly two-year average IOU Residential Loads based on actual loads as submitted by Exchanging Utilities, and the monthly Forecast COU Exchange Loads.

Table 8.2 Forecast Average System Costs (ASCs)
Table lists the Fiscal Year Forecasted ASCs in $/MWh as determined through the ASC review.

Table 8.1

IOUs FY 2016 - 2017 Residential Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**FY 2016**
2	Avista	254,400	286,391	420,321	454,730	426,955	374,469	309,851	274,086	243,614	262,544	303,040	286,937	**3,897,339**
3	Idaho Power	449,427	432,485	571,412	643,022	646,777	501,437	425,494	459,557	528,687	663,892	747,534	693,475	**6,763,201**
4	NorthWestern	47,071	51,349	68,144	72,747	66,539	62,909	53,085	48,414	47,926	52,069	55,694	52,850	**678,797**
5	PacifiCorp	583,749	657,134	987,430	1,055,914	886,730	755,576	642,733	619,364	666,921	707,545	768,697	674,002	**9,005,795**
6	PGE	578,537	649,913	928,228	988,358	869,970	755,895	658,189	609,488	577,986	640,288	681,445	661,684	**8,599,980**
7	Puget Sound Energy	766,469	940,068	1,271,040	1,383,344	1,269,404	1,157,392	1,009,263	849,358	731,718	748,804	760,883	729,693	**11,617,436**
8														
9		**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**FY 2017**
10	Avista	254,400	286,391	420,321	454,730	426,955	374,469	309,851	274,086	243,614	262,544	303,040	286,937	**3,897,339**
11	Idaho Power	449,427	432,485	571,412	643,022	646,777	501,437	425,494	459,557	528,687	663,892	747,534	693,475	**6,763,201**
12	NorthWestern	47,071	51,349	68,144	72,747	66,539	62,909	53,085	48,414	47,926	52,069	55,694	52,850	**678,797**
13	PacifiCorp	583,749	657,134	987,430	1,055,914	886,730	755,576	642,733	619,364	666,921	707,545	768,697	674,002	**9,005,795**
14	PGE	578,537	649,913	928,228	988,358	869,970	755,895	658,189	609,488	577,986	640,288	681,445	661,684	**8,599,980**
15	Puget Sound Energy	766,469	940,068	1,271,040	1,383,344	1,269,404	1,157,392	1,009,263	849,358	731,718	748,804	760,883	729,693	**11,617,436**
16														
17														
18							COUs FY 2016 - 2017 Forecast Exchange Loads							
19							(MWh)							
20														
21		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**FY 2016**
22	Clark	174,112	229,882	289,295	280,837	230,235	227,160	178,573	162,901	144,514	163,017	163,564	143,600	**2,387,690**
23	Snohomish	249,419	247,444	397,801	463,134	411,532	420,243	351,532	298,978	264,955	233,191	234,125	211,829	**3,784,183**
24														
25		**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**FY 2017**
26	Clark	173,579	228,945	287,891	279,587	224,687	226,473	177,885	162,720	144,634	163,464	163,984	143,637	**2,377,487**
27	Snohomish	253,510	251,502	404,327	471,010	418,530	427,390	357,509	304,062	269,461	237,156	238,107	215,432	**3,847,996**

Table 8.2

Forecast Average System Costs (ASCs)
($/MWh)

	A	B	C
1		**FY 2016**	**FY 2017**
2	Avista	$ 50.87	$ 50.87
3	Idaho Power	$ 59.02	$ 59.02
4	NorthWestern	$ 79.24	$ 79.24
5	PacifiCorp	$ 76.42	$ 76.42
6	PGE	$ 71.14	$ 71.14
7	Puget Sound Energy	$ 67.09	$ 67.09
8	Clark	$ 50.95	$ 50.95
9	Snohomish	$ 49.59	$ 49.85
10			
11	Note: Rate Period ASCs are determined through the ASC review process		