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

BP-14 Final Rate Proposal

Power Rates Study Documentation

BP-14-FS-BPA-01A

July 2013

2014 POWER RATES STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

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

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

DOCUMENTATION FOR THE 2014 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: Rate setting Methodology and Process contains ratemaking tables that are the output of the Rate Analysis Model (RAM2014). The RAM2014 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. The output tables of RAM2014 include billing determinants, which are based on power sales forecasts, and revenue requirements used in the PRS cost of service analysis (COSA). Other tables show the initial allocation of the revenue requirement over the billing determinants. Next, tables present the rate design steps, the basis for which is section 7 of the Northwest Power Act. The final table shows the calculation of the resource cost contributions that appear in GRSP section 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 Resource Support Service (RSS) modules of RAM. The Tier 2 module results include the Tier 2 rates, billing determinants, and rate design adjustments associated with Tier 2. The results of the RSS module include the rate design revenue credits and adjustments associated with RSS and Resource Shaping Charge, the RSS rates and charges, the Resources Shaping charge, the Transmission Scheduling Service charge, and the grandfathered Generation Management Service charge.

Section 4: Revenue Forecast documents revenue forecasts at both current and proposed rates for the rate period, FY 2014-2015, and at current rates for the period immediately proceeding the two-year rate period, FY 2013.

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 Residential Exchange Loads and costs, and Forecasted Average System Costs (ASCs).

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SECTION 1: INTRODUCTION AND BACKGROUND

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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-14-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, the 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 2014-2015.

The HYDSIM studies incorporate the power and non-power operating requirements BPA expects to be in effect during the rate period, including those described by the NOAA Fisheries in its Biological Opinion (BiOp), published May 5, 2008; the United States Fish and Wildlife Service (USFWS) BiOp, published December 2000; operations described in the Northwest Power and Conservation Council's Fish and Wildlife Program; and other fish mitigation measures. Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow augmentation, minimum flow levels, spill for juvenile fish passage, reservoir drawdown limitations, and turbine operation efficiency requirements. HYDSIM uses hydro plant operating characteristics in combination with the 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-14-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-14-FS-BPA-04):

Secondary Energy Revenue Forecast

RevSim 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 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 and the Power Services 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 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 making all scheduled Treasury payments on time and in full.

Risk Mitigation

The ToolKit Model is used to determine Treasury Payment Probability (TPP, the probability of making all 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 electric energy price results from the Power Risk and Market Price Study are used as price inputs in the Generation Inputs Study to value the energy in synchronous condensing, generation dropping, and station service. The market price run is used in the Power Rates Study for:

(a) the prices for surplus sales and balancing purchases in RAM2014,
(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-14-FS-BPA-01):

Rate Analysis Model (RAM2014)

RAM2014, 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. <u>Cost of Service Analysis</u>. 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 RAM2014 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 TRM specifies a cost allocation methodology to PF Preference costs allocated in the COSA and Rate Directives steps. RAM2014 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 RAM2014 using unique database keys.
Three rate designs are developed: (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. RAM2014 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 Resource Support Services 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 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, 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.

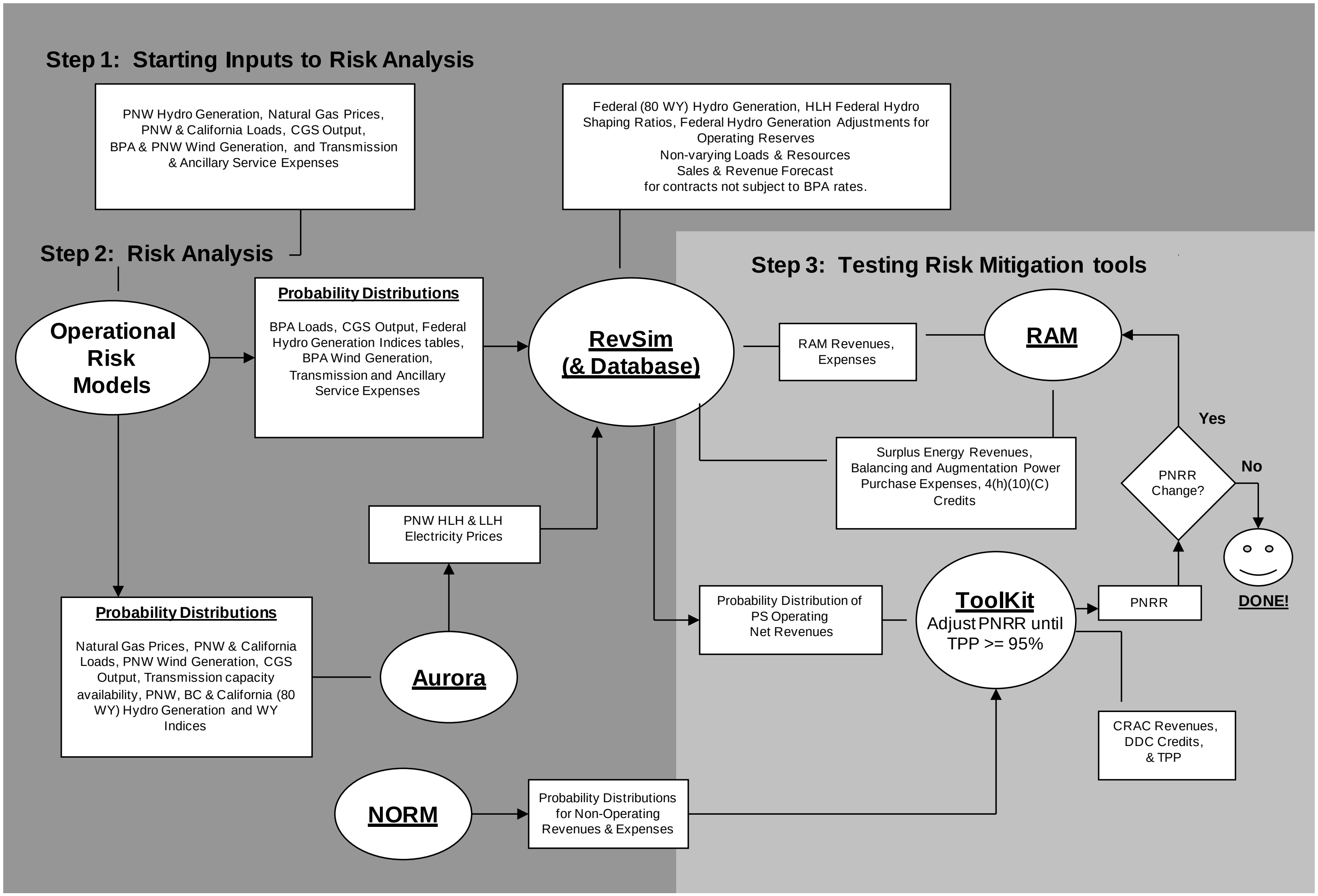
Revenue and Purchased Power Expense Forecast

The Revenue Forecast, section 4 of the Power Rates Study, presents BPA's expected level of revenue and purchased power expense for FY 2013-2015. FY 2013 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected purchased power 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, such as output from RiskMod, to obtain short-term marketing revenues, balancing purchased power expenses, augmentation purchased power expenses, and 4(h)(10)(C) credits.

FY 2014-2015 Average System Cost (ASC) Forecasts

ASCs are used in determining the forecast of REP benefits that exchanging utilities are entitled to during the rate period. For purposes of the Final Proposal, BPA is using the Final Report ASCs published by BPA on July 22, 2013.

Rate Development Process Chart



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SECTION 2: RATESETTING METHODOLOGY AND PROCESS

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Table Descriptions

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 04-3)
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 Calculation of Annual Energy Rate Scalars for 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 Calculation of Monthly Energy Rates Scalars for 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 Reallocation 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 IP 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 IP 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 Base Exchange 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)
Reallocation of “Lookback” REP Refund amounts under the 2012 REP Settlement Agreement, Section 6, prescribes how the Settlement equitably recognized differences in outstanding

lookback obligations at the time of the Settlement. This table shows the reallocation balances through time as of the 7(i) process through 2020.

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-14 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 Reallocation of 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 Calculation of Annual Energy Rate Scalars for Second IP-PF Link Rate Calculation (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 Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation (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 and Recalculation of Rates (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)
Worksheet shows that computation of constant annual benefits over the rate period is equivalent with allocation of separate year costs in each separate year of the rate period.

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 RAM2014. 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 Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output (DS 04)
Worksheet calculates the change in the T1SFCO from the RHWM to 7(i) Processes, and values the difference at the system augmentation price when system augmentation amount is greater than zero.

Table 2.5.5 Calculation of Load Shaping and Demand Revenues (DS 05)
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 2.5.6 Calculation of PF Public Rates under Tiered Rate Methodology (DS 06)
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 2.5.7.1 Calculation of Net REP Ratemaking and Recovery Demonstration (DS 07-1)
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 2.5.7.2 TRM PFp Revenues Equal to Non-TRM PFp Revenues (DS 07-2)
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 2.5.8.1 Calculation of Priority Firm Public Tier 1 Rate Equivalent Components (DS 08-1)
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 2.5.8.2 Calculation of Priority Firm Public Melded Rate Equivalent Components (DS 08-2)
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 2.5.8.3 Calculation of Industrial Firm Power Rate Components (DS 08-3)
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 2.5.8.4 Calculation of New Resource Rate Components (DS 08-4)
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 2.5.8.5 Calculation of the Load Shaping True-up Rate (DS 08-5)
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 2.5.9.1 Allocated Costs and Unit Costs, Priority Firm Power Rates (DS 09-1)
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 2.5.9.2 Allocated Costs and Unit Costs, Industrial Firm Power (DS 09-2)
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 2.5.9.3 Allocated Costs and Unit Costs, New Resource Firm Power (DS 09-3)
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 2.5.9.4 Resource Cost Contribution (DS 09-4)
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 2013 - September 2015
(MWh)

	A	B	C	E	F
4				2014	2015
5	Preference			61,172,528	61,862,025
6		Block		215,417	231,938
7		Slice Block		15,482,671	16,251,180
8		Slice (non-block)		16,947,897	16,302,184
9		Load Following - System Shape		28,485,325	28,539,521
10		Load Following - Load Shaping		-113,432	-123,066
11		Tier 2 (Block)		154,649	660,267
12	Industrial			2,733,123	2,733,123
13		Smelter		2,628,000	2,628,000
14		Other Industrial		105,123	105,123
15	New Resource			9	9
16	Firm Power and Services			7,692,998	7,525,017
17		Intraregional Transfer		808,609	808,610
18			WNP3	729,769	729,770
27				0	0
28		FBS Obligation		6,270,319	6,102,338
29			Canadian Entitlement	4,241,418	4,073,436
30			USBR Pump Load	1,578,384	1,578,384
31			Hungry Horse	65,238	65,238
32			Upper Baker	11,228	11,228
33			Non-Treaty Storage	91,812	91,812
38				0	0
39		Seasonal or Capacity Exchange		614,069	614,069
40			Riverside Capacity	43,650	43,650
41			Riverside Seasonal	58,560	58,560
42			Pasadena Capacity	9,900	0
43			Pasadena Seasonal	21,960	21,960
44			PG&E	234,264	231,784
51	Irrigation Mitigation			0	0
52	Conservation			-260,321	-260,321

Rate Data Input
Disaggregated Resources
Test Period October 2013 - September 2015
(MWh)

	A	B	C	E	F
5				2014	2015
6	Hydro			60,692,458	59,597,656
7		Regulated		57,596,683	56,501,881
8		Independent		3,095,775	3,095,775
9			Cowlitz Falls	232,343	232,343
10			Idaho Falls	123,900	123,900
18				0	0
19		Hydro Other		1,482,400	1,477,392
20			Canadian Entitlement	1,194,400	1,189,392
21			Libby Coordination	288,000	288,000
29				0	0
30	Non Hydro			10,521,124	9,024,029
31		Water		23,039	23,039
32			Dworshak/Clearwater Small Hydropower	23,039	23,039
33			Elwha Hydro	0	0
41				0	0
42		Thermal		9,022,800	7,687,488
52				0	0
53		Wind		403,655	403,655
54			Foote Creek 1	35,366	35,366
55			Foote Creek 2	4,162	4,162
56			Foote Creek 4	38,785	38,785
57			Stateline Wind Project	181,202	181,202
58			Condon Wind Project	84,510	84,510
63				0	0
64		Renewable		168,358	168,358
65			Georgia-Pacific Paper (Wauna)	168,331	168,331
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	27	27
74				0	0

Rate Data Input
Disaggregated Resources
Test Period October 2013 - September 2015
(MWh)

	A	B	C	E	F
5				2014	2015
75	Contracts			903,272	741,489
76		Imports		409,029	394,361
77			Riverside Exchange Energy	64,339	64,339
78			Pasadena Exchange Energy	16,388	13,991
79			BC Hydro Power Purchase	8,760	8,760
80			Slice Return of Losses	319,542	307,271
86				0	0
87		Seasonal or Capacity Exchange		494,243	347,128
88			Riverside Capacity	43,650	43,651
89			Riverside Seasonal	58,560	58,560
90			Pasadena Capacity	9,900	150
91			Pasadena Seasonal	21,813	18,622
92			PG&E	226,246	226,145
97				0	0
98		Tier2		0	0
99			Short Term	0	0
100			Load Growth	0	0
101			Vintage 1	0	0
102			Vintage 2	0	0
108				0	0
109	Augmentation and Balancing			470,994	3,591,440
110		System Augmentation		344,342	3,464,788
111		Balancing		0	0
112		Tier 1 Resources		126,652	126,652
113			Klondike III	124,449	124,449
114			Rocky Brook	2,203	2,203
115					
116	Transmission Losses			(2,063,309)	(2,078,073)

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2013 - September 2015

	B	D	E
7	**Exchange ASCs ($/MWh)**	**2014**	**2015**
8			
9	Avista Corporation	$ 57.05	$ 57.05
10	Idaho Power Company	$ 50.22	$ 50.22
11	NorthWestern Energy, LLC	$ 70.65	$ 70.65
12	PacifiCorp	$ 65.61	$ 65.61
13	Portland General Electric Company	$ 68.99	$ 68.99
14	Puget Sound Energy, Inc.	$ 76.83	$ 76.83
15	Clark Public Utilities	$ 49.91	$ 49.91
17	Snohomish County PUD No 1	$ -	$ -
18			
19	**Exchange Loads (GWh)**	**2014**	**2015**
20			
21	Avista Corporation	3,868	3,868
22	Idaho Power Company	6,427	6,427
23	NorthWestern Energy, LLC	668	668
24	PacifiCorp	9,235	9,235
25	Portland General Electric Company	8,664	8,664
26	Puget Sound Energy, Inc.	12,024	12,024
27	Clark Public Utilities	2,540	2,523
29	Snohomish County PUD No 1	0	0
30		43,426	43,409
31			
32	**Exchange Resource Cost ($000)**	**2014**	**2015**
33			
34	Avista Corporation	$ 220,644	$ 220,644
35	Idaho Power Company	$ 322,773	$ 322,773
36	NorthWestern Energy, LLC	$ 47,208	$ 47,208
37	PacifiCorp	$ 605,918	$ 605,918
38	Portland General Electric Company	$ 597,705	$ 597,705
39	Puget Sound Energy, Inc.	$ 923,790	$ 923,790
40	Clark Public Utilities	$ 126,790	$ 125,932
42	Snohomish County PUD No 1	$ -	$ -
43		$ 2,844,827	$ 2,843,969

Energy Allocation Factor
Power Sales and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	E	F
4			**2014**	**2015**
5	**Sales**			
6	Public			
7		Load Following System Shape	3,252	3,258
8		Load Following Load Shaping	(13)	(14)
9		Tier 2 (block)	17.654	75.373
10		Block Service	25	26
11		Slice (output energy)	1,935	1,861
12		Slice (block)	1,767	1,855
13		Undistributted Conservation	(30)	(30)
14	Exports			
15		BC Hydro (Cdn Entitlement)	484	465
16		Non-Treaty Storage	10	10
17		Libby Coordination	32	32
18		Pasadena Capacity	1.1	0
19		Pasadena Seasonal	2.5	3
20		Riverside Capacity	5	5
21		Riverside Seasonal	7	7
22		PG&E	27	26
23		Intertie Losses	1	1
24	Intra-regional Transfers			
25		Avista (WNP#3 Settle.)	83	83
26		Dittmer/Substration Sale	9	9
27	Other Loads			
28		USBR Pump Load	180	180
29		Hungry Horse	7	7
30		Upper Baker	1	1
31		Direct Service Industries	312	312
32		New Resource	0.0	0
33	Total Firm Obligations		**8,117**	**8,175**
34				
35	**Resources**			
36	Hydro			
37		Regulated	6,575	6,450
38		Independent		
39		Cowlitz Falls	27	27
40		Idaho Falls	14	14
41		PreAct	313	313
42		Non-Fed CER (Canada)	136	136
43		Libby Coordination	33	33
44	Other Hydro Resources			
45				

Energy Allocation Factor
Power Sales and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	E	F
4			**2014**	**2015**
46	Combustion Turbines			
47	Renewables			
48		Foote Creek 1	4	4
49		Foote Creek 2	0	0
50		Foote Creek 4	4	4
51		Stateline Wind Project	21	21
52		Condon Wind Project	10	10
53		Klondike I	7	7
54		Georgia-Pacific Paper (Wauna)	19	19
55		Klondike III	14	14
56		Fourmile Hill Geothermal	0	0
57		Ashland Solar Project	0	0
58		White Bluffs Solar	0	0
59	Cogeneration			
60	Imports			
61		Riverside Exchange Energy	7	7
62		Pasadena Exchange Energy	2	2
63		BC Hydro Power Purchase	1	1
64		Riverside Capacity	5	5
65		Riverside Seasonal	7	7
66		Pasadena Capacity	1	0
67		Pasadena Seasonal	2	2
68		Slice Losses Return	36	35
69	Regional Transfers (In)			
70		PG&E	26	26
71		PacifiCorp	15	0
72	Large Thermal		1,030	878
73	Non-Utility Generation			
74		Dworshak/Clearwater Small Hydropower	3	3
75		Elwha Hydro	0	0
76		Glines Canyon Hydro	0	0
77		Rocky Brook	0.25	0.25
78	Augmentation Purchases		0	0
79	Tier 2 Purchases		18	78
80	Federal Trans. Losses		(236)	(237)
81	Total Net Resources		**8,096**	**7,857**
82				
83	Total Firm Surplus/Deficit		**(21)**	**(318)**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	D	E
4			**2014**	**2015**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	25	27
10		Slice (block)	1,819	1,909
11		Load Following System Shape	3,346	3,352
12		Load Following Load Shaping	(13)	(14)
13		Slice (output energy)	1,991	1,915
14		Tier 2	18.17	77.56
15		Undistributted Conservation	(31)	(31)
16		5(c) Exchange	5,101	5,099
17	Industrial Firm - 7(c) Loads			
18		Direct Service Industries	321	321
19	New Resources - 7(f) Loads			
20		NR	0.001	0.001
21	Surplus Firm - SP Loads			
22		Avista (WNP#3 Settle.)	86	86
23		Dittmer/Substation Sale	9	9
24	Total Loads		**12,672**	**12,751**
25				
26	**Resources**			
27	Federal Base System			
28		Hydro	7,057	6,931
29		Other Resources		
30		Small Thermal & Misc.		
31		Combustion Turbines		
32		Renewables	0	0
33		Cogeneration		
34		Imports	26	24
35		Regional Transfers (In)	41	26
36		Large Thermal	1,030	878
37		Non-Utility Generation	0	0
38		Slice Loss Return	36	35
39		Augmentation Purchases	21.14	317.96
40		Tier 2 Purchases	18	78

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	D	E
4			**2014**	**2015**
41	less: FBS Obligations			
42		BC Hydro (Cdn Entitlement)	(498)	(478)
43		Non-Treaty Storage	(11)	(11)
44		Libby Coordination	(33)	(33)
45		Hungry Horse	(8)	(8)
46		Upper Baker	(1)	(1)
47		USBR Pump Load	(185)	(185)
48	less: FBS Uses			
49		Pasadena	(4)	(3)
50		Riverside	(12)	(12)
51		PG&E	(28)	(27)
52		Intertie Losses	(1)	(1)
53	Exchange Resources			
54		5(c) Exchange	5,101	5,099
55	New Resources			
56		Cowlitz Falls	27	27
57		Idaho Falls	14	14
58		Foote Creek 1	4	4
59		Foote Creek 2	0	0
60		Foote Creek 4	4	4
61		Stateline Wind Project	21	21
62		Condon Wind Project	10	10
63		Klondike I	7	7
64		Klondike III	14	14
65		Georgia-Pacific Paper (Wauna)	19	19
66		Fourmile Hill Geothermal	0	0
67		Ashland Solar Project	0	0
68		White Bluffs Solar	0	0
69		Dworshak/Clearwater Small Hydropower	3	3
70		Elwha Hydro	0	0
71		Glines Canyon Hydro	0	0
72		Rocky Brook	0	0
73	Total Resources		**12,672**	**12,751**

Table 2.2.3.1

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
6	**Loads (after adjustments)**		
7	Public	7,130	7,209
8	Exchange	5,101	5,099
9	DSI	321	321
10	NR	0.001	0.001
11	FPS	95	95
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,231	12,308
15	Industrial Firm - 7(c) Loads	321	321
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	95	95
18	Total Firm Loads	12,647	12,724
19	Secondary	2,264	2,254
20	Surplus Firm - SP Loads (for rate protection)	95	95
22	**Resources (after adjustments)**		
23	Federal Base System	7,448	7,529
24	Exchange Resources	5,101	5,099
25	New Resources	123	123
26	Total Firm Resources	12,672	12,751
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,448	7,529
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	4,783	4,779
36	Industrial Firm - 7(c) Loads	246	247
37	New Resources - 7(f) Loads	0.0008	0.0008
38	Surplus Firm - SP Loads	73	73
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	75	74
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	22	22

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9870	0.9874
48	Industrial Firm - 7(c) Loads	0.0100	0.0097
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0030	0.0029
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	0.9376	0.9372
58	Industrial Firm - 7(c) Loads	0.0482	0.0485
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0142	0.0143
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.7717	0.7717
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.2283	0.2283
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9671	0.9673
68	Industrial Firm - 7(c) Loads	0.0254	0.0252
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0075	0.0075
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9744	0.9746
83	Industrial Firm - 7(c) Loads	0.0256	0.0254
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	0.6556	0.6563
91	Industrial Firm - 7(c) Loads	0.0413	0.0413
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3032	0.3023

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	298,751	338,558
8	Bureau of Reclamation	140,601	143,033
9	Corps of Engineers	225,687	231,878
10	Billing Credits Generation	5,825	5,935
11	Cowlitz Falls O&M	3,401	3,427
12	Idaho Falls Bulb Turbine	4,648	4,880
13	Bureau O&M - Elwha	-	1
14	Clearwater Hatchery Generation	1,060	1,080
15	New Resources Integration Wheeling	941	983
16	Wauna	10,125	10,315
17	Other New Resources	-	-
18			
19	**Operating Generation Settlement Payment**		
20	Operating Generation Settlement Payment (Colville)	21,405	21,906
21			
22	**Non-Operating Generation**		
23	Trojan Decomissioning	1,500	1,500
24	WNP-1&3 Decomissioning	706	728
25			
26	**Contracted and Augmentation Power Purchases**		
27	Augmentation Power Purchases	6,199	94,914
28	Balancing Purchases	27,421	26,720
29	PNCA Headwater Benefits	2,957	3,030
30	Tier 1 Augmentation Resources (Klondike III)	10,000	9,997
31	Hedging/Mitigation	35,044	-
32	Other Committed Purchase (excl. Hedging)	-	-
33	Bookout Adj to Contracted Power Purchases	-	-
34			
35	**Exchanges and Settlements**		
36	Residential Exchange (IOU)	197,500	197,500
37	Residential Exchange (COU)	3,019	2,998
38	Residential Exchange (Refund)	76,538	76,538
39	Residential Exchange Program Support	973	996
40	Residential Exchange Interest Accrual	1,400	1,400
41			
42	**Renewable and Conservation Generation**		
43	Renewables R&D	4,944	5,045
44	Renewable Generation	29,798	30,150
45	Green Energy Premium (contra-expense)	(750)	(750)
46	Generation Conservation R&D	872	890
47	DSM Technology	-	-
48	Conservation Acquisition	16,444	16,754
49	Low Income Energy Efficiency	5,155	5,252
50	Reimbursable Energy Efficiency Development	11,859	12,083
51	Legacy Conservation	1,031	1,050
52	Market Transformation	13,919	14,180

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
53			
54	**Transmission Acquisition and Ancillary Services**		
55	Trans & Ancillary Svcs	59,274	57,485
56	Trans & Ancillary Svcs (sys oblig)	36,442	36,989
57	Third Party GTA Wheeling	55,533	56,578
58	Power 3rd Party Trans & Ancillary Svcs	2,288	2,333
59	Trans Acq Generation Integration	11,256	11,664
60	Power Telemetering/Equipment Replacement	52	53
61			
62	**Power Non-Generation Operations**		
63	Efficiencies Program	-	-
64	Systems Operations R&D	-	-
65	Information Technology	6,602	6,735
66	Generation Project Coordination	6,826	6,968
67	Slice costs Charged to Slice Customers	-	-
68	Slice Implementation	1,099	1,126
69			
70	**PS Scheduling**		
71	Operations Scheduling	10,398	10,621
72	Scheduling R&D	-	-
73	Operations Planning	7,641	7,948
74			
75	**PS Marketing and Business Support**		
76	Sales and Support	20,951	21,339
77	Strategy, Finance & Risk Mgmt	18,299	19,373
78	Executive and Administrative Svcs	4,157	4,360
79	Conservation Support	9,094	9,309
80			
81	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
82	Fish and Wildlife	254,000	260,000
83	USF&W Lower Snake Hatcheries	30,670	31,670
84	Planning Council	10,568	10,799
85	Environmental Requirements	300	300
86			
87	**BPA Internal Support**		
88	Additional Post-Retirement Contribution	18,501	18,819
89	Agency Svs for Power for Rev Req schedule	44,815	46,494
90	Agency Svs for Energy Efficiency for Rev Req schedule	10,287	10,721

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
91			
92	**Bad Debt Expense/Other**		
93	Bad Debt Expense (composite)	-	-
94	Bad Debt Expense (non-slice)	-	-
95	Other Income, Expenses, Adjustments (composite)	-	-
96	Other Income, Expenses, Adjustments (non-slice)	-	-
97			
98	**Non-Federal Debt Service**		
99	**Energy Northwest Debt Service**		
100	CGS Debt Service	89,776	80,636
101	WNP-1 Debt Service	248,237	184,536
102	WNP-3 Debt Service	165,601	166,975
103	EN Retired Debt	-	-
104			
105	**Non-Energy Northwest Debt Service**		
106	Conservation (CARES) Debt Service	2,418	312
107	Cowlitz Falls (Lewis County) Debt Service	6,885	6,890
108	Northern Wasco Debt Service	1,931	1,929
109			
110	**Depreciation and Amortization**		
111	**Depreciation**		
112	Depreciation - BPA	14,699	17,006
113	Depreciation - Corps	85,081	88,984
114	Depreciation - Bureau	26,728	28,174
115			
116	**Amortization**		
117	Amortization - Legacy Conservation	13,930	9,649
118	Amortization - Conservation Acquisitions	44,860	43,373
119	Amortization - CRFM	7,729	7,729
120	Amortization - Fish & Widlife	31,421	34,366
121			
122	**Interest Expense**		
123	**Net Interest**		
124	Interest On Appropriated Funds	222,306	220,657
125	Capitalization Adjustment	(45,937)	(45,937)
126	Interest On Treasury Bonds	63,653	73,235
127	Non Federal Interest (Prepay)	14,775	14,041
128	Capitalized Bond Premium	-	-
129	AFUDC	(11,168)	(11,175)
130	Interest Earned on BPA Fund for Power (composite)	(7,927)	(11,918)
131	Prepay Offset Credit	(6,950)	(2,035)
132	Interest Earned on BPA Fund for Power (non-slice)	(930)	124

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
133			
134	**Net Interest into Cost Pools**		
135	Power Net Interest - Hydro Allocation	184,010	192,202
136	Power Net Interest - Fish & Wildlife Allocation	19,842	20,328
137	Power Net Interest - Conservation Allocation	21,011	21,727
138	Power Net Interest - BPA Programs Allocation	2,959	2,734
139			
140	**Net Interest into Cost Pools 7b2**		
141	Power Net Interest Hydro 7b2 Allocation	182,054	191,514
142	Power Net Interest Fish & Wildlife 7b2 Allocation	19,631	20,254
143	Power Net Interest BPA Programs 7b2 Allocation	23,716	24,374
144			
145	**Net Revenue**		
146	**Minimum Required Net Revenue**		
147	Repayment of Treasury Borrowings	30,611	111,151
148	Payment of Irrigation Assistance	52,550	52,110
149	Depreciation (MRNR - Reverse sign)	(126,508)	(134,164)
150	Amortization (MRNR - Reverse sign)	(97,940)	(95,117)
151	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
152	Capitalized Bond Premium (Reverse Sign)	-	-
153	Repayment of Federal Appropriations	76,000	-
154	Accrual Revenues (MRNR Adjustment - Reverse Sign)	3,524	3,524
155	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
156	Non Federal Interest (Prepay) (MRNR - Reverse sign)	(14,775)	(14,041)
157	Revenue Financing Requirement	-	-
158	Depreciation Exceeds Cash Expense	-	-
159			
160	**Minimum Net Revenue into Cost Pools**		
161	Power MNetRev - Hydro Allocation	-	-
162	Power MNetRev - Fish & Wildlife Allocation	-	-
163	Power MNetRev - Conservation Allocation	-	-
164	Power MNetRev - BPA Programs Allocation	-	-
165			
166	**Minimum Net Revenue into Cost Pools 7b2**		
167	Power MNetRev - Hydro 7b2 Allocation	-	-
168	Power MNetRev - Fish & Wildlife 7b2 Allocation	-	-
169	Power MNetRev - PBA Programs 7b2 Allocation	-	-
170			
171	**Planned Net Revenues for Risk into Cost Pools**		
172	Power PNetRev - Hydro Allocation	-	-
173	Power PNetRev - Fish & Wildlife Allocation	-	-
174	Power PNetRev - Conservation Allocation	-	-
175	Power PNetRev - BPA Programs Allocation	-	-
176			
177	**Planned Net Revenues for Risk into Cost Pools 7b2**		
178	Power PNetRev - Hydro 7b2 Allocation	-	-
179	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-
180	Power PNetRev - BPA Programs 7b2 Allocation	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
181			
182	**Internally Computed Line Items**		
183	Augmentation Power Purchases	6,199	94,914
184	Balancing Purchases	62,464	26,720
185	Secondary Energy Credit	(322,152)	(340,317)
186	Low Density Discount Costs	35,303	36,361
187	Irrigation Rate Mitigation Costs	18,816	18,816
188	**Charges/Credits to Tiered Rate Pools**		
189	Firm Surplus and Secondary Credit (from unused RHWM)	(3,299)	(2,383)
190	Balancing Augmentation	24,714	(4,995)
191	Transmission Loss Adjustment	(27,450)	(28,010)
192	Demand Revenue	42,954	43,388
193	Load Shaping Revenue	3,422	22,791
194	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
195	Augmentation RSS & RSC Adder	2,513	2,513
196	Tier 2 Purchase Costs	5,296	24,869
197	Tier 2 Rate Design Adjustments (Cost)	206	901
198	Tier 2 Other Costs	-	-
199			
200	**Revenue Credits / Rate Design Adjustments**		
201	Downstream Benefits and Pumping Power	(15,393)	(15,394)
202	Generation Inputs for Ancillary and Other Services Revenue	(117,696)	(112,910)
203	4(h)(10)(c)	(97,173)	(92,996)
204	Colville and Spokane Settlements	(4,600)	(4,600)
205	Green Tags (FBS resources)	-	-
206	Green Tags (New resources)	(1,061)	(1,107)
207	Energy Efficiency Revenues	(11,859)	(12,083)
208	Miscellaneous Credits (incl. GTA)	(3,225)	(3,240)
209	Pre-sub/Hungry Horse	(1,842)	(1,909)
210	Other Locational/Seasonal Exchange	(701)	(701)
211	Upper Baker	(422)	(446)
212	WNP3 Settlement	(29,163)	(29,163)
213	Other Long-Term Contracts	-	-
214	Network Wind Integration & Shaping	-	-
215	**Tier 2**		
216	Composite Augmentation RSS Revenue Debit/(Credit)	(1,972)	(1,972)
217	Composite Tier 2 RSS Revenue Debit/(Credit)	(23)	(99)
218	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(182)	(802)
219	Composite Non-Federal RSS Revenue Debit/(Credit)	(687)	(958)
220	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(541)	(541)
221	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
222	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
223	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	184	200

Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2013 - September 2015
($ 000)

	B	D	E
3		**2014**	**2015**
4			
5	**Federal Base System**	**1,919,734**	**1,994,734**
6	Hydro	724,868	748,606
7	Operating Expense	540,858	556,404
8	Net Interest	184,010	192,202
9	PNRR	-	-
10	MRNR	-	-
11	BPA Fish and Wildlife Program	316,130	325,792
12	Operating Expense	296,288	305,464
13	Net Interest	19,842	20,328
14	PNRR	-	-
15	MRNR	-	-
16	Trojan	1,500	1,500
17	WNP #1	248,943	185,264
18	WNP #2	388,527	419,194
19	WNP #3	165,601	166,975
20	System Augmentation	6,199	94,914
21	Balancing	62,464	26,720
22	Tier 2 Costs	5,502	25,769
23			
24	**New Resources**	**72,983**	**73,947**
25	Idaho Falls	4,648	4,880
26	Tier 1 Aug (Klondike III)	10,000	9,997
27	Cowlitz Falls	10,286	10,317
28	Other NR	48,049	48,753
29			
30	**Residential Exchange**	**2,847,200**	**2,846,365**
31			
32	**Conservation**	**156,705**	**151,235**
33	Operating Expense	135,694	129,508
34	Net Interest	21,011	21,727
35	PNRR	-	-
36	MRNR	-	-
37			
38	**BPA Programs**	**156,947**	**163,523**
39	Operating Expense	153,988	160,789
40	Net Interest	2,959	2,734
41	PNRR	-	-
42	MRNR	-	-
43			
44			
45	**Transmission**	**164,845**	**165,102**
46	TBL Transmission/Ancillary Services	107,024	106,191
47	3Rd Party Trans/Ancillary Services	2,288	2,333
48	General Transfer Agreements	55,533	56,578
49			
50	**Total PBL Revenue Requirement**	**5,318,414**	**5,394,907**
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 2013 - September 2015
($ 000)

	B	D		E		F	G	H
18	**Program Totals**		**2014**		**2015**			
19	**Low Density Discount Expenses........................**	**$**	**35,303**	**$**	**36,361**			
20	**Irrigation Rate Discount....................................**	**$**	**18,816**	**$**	**18,816**			
21								
22								
23	**TRM Costs after Adjustments**		**2014**		**2015**			
24	**Composite...**	$	2,308,843	$	2,318,682			
25	**Non-Slice...**	$	(258,691)	$	(260,204)			
26	**Slice..**	$	-	$	-			
27	**Tier 2..**	$	5,502	$	25,769			
28	**Total Costs**	$	2,055,654	$	2,084,247			
29								
30	**Low Density Discount**							
31	**Customer Charge LDD**		**2014**		**2015**			
32	**TOCA LDD Offest %..**		1.63%		1.67%			
33	**LDD Customer Charge ($000).........................**	$	33,356	$	34,312			
34								
35	**Irrigation Rate Discount**							
36	**IRD Percentage..**		37.06%					
37	**Total Irrigation Load (MWh)..........................**		1,881,605					
38	**RT1SC..**		7,116					
39	**Irrigation Load Weighted LDD.......................**		4.90%					
40								
41			**2014**		**2015**			
42	**Hours..**		8760		8760			
43	**IRD TOCA...**		3.01853%		3.01853%			
44	**Composite Revenue...**	$	71,033,966	$	71,033,966			
45	**Non-Slice Revenue..**	$	(10,923,507)	$	(10,923,507)			
46	**Load Shaping Revenue......................................**	$	(6,704,292)	$	(6,704,292)			
47	**Total after LDD...**	$	50,789,265	$	50,789,265			
48								
49	**Irrigation Rate Discount...................................**		**10.00**					
50								
51								

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2013 - September 2015
($ 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-13	18,568	(4,470)	$ 9.33	$ 31.59	$ 32,023
54	Oct-13	-	672	$ 9.33	$ 27.43	$ 18,443
55	Nov-13	14,950	(9,070)	$ 10.50	$ 35.56	$ (165,546)
56	Nov-13	-	(899)	$ 10.50	$ 31.27	$ (28,106)
57	Dec-13	23,262	1,347	$ 11.47	$ 38.84	$ 319,125
58	Dec-13	-	5,498	$ 11.47	$ 33.27	$ 182,922
59	Jan-14	25,171	(1,091)	$ 11.17	$ 37.80	$ 239,919
60	Jan-14	-	7,042	$ 11.17	$ 30.67	$ 216,005
61	Feb-14	15,051	4,321	$ 10.90	$ 36.89	$ 323,458
62	Feb-14	-	6,561	$ 10.90	$ 30.60	$ 200,794
63	Mar-14	16,004	647	$ 8.93	$ 30.23	$ 162,489
64	Mar-14	-	1,114	$ 8.93	$ 25.10	$ 27,946
65	Apr-14	18,485	11,098	$ 7.61	$ 25.76	$ 426,564
66	Apr-14	-	6,785	$ 7.61	$ 20.12	$ 136,519
67	May-14	14,092	(21,976)	$ 6.20	$ 21.00	$ (374,069)
68	May-14	-	(9,927)	$ 6.20	$ 13.08	$ (129,800)
69	Jun-14	10,835	(9,099)	$ 6.72	$ 22.73	$ (133,979)
70	Jun-14	-	(1,333)	$ 6.72	$ 14.57	$ (19,417)
71	Jul-14	17,923	(7,917)	$ 9.01	$ 30.49	$ (79,884)
72	Jul-14	-	6,478	$ 9.01	$ 24.50	$ 158,688
73	Aug-14	15,963	603	$ 10.03	$ 33.96	$ 180,588
74	Aug-14	-	4,538	$ 10.03	$ 27.09	$ 122,913
75	Sep-14	12,949	(2,231)	$ 9.94	$ 33.65	$ 53,642
76	Sep-14	-	2,734	$ 9.94	$ 27.90	$ 76,296
77	**Total**					**$ 1,947,532**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2013 - September 2015
($ 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-14	19,913	(5,103)	$ 9.33	$ 31.59	$ 24,573
80	Oct-14	-	361	$ 9.33	$ 27.43	$ 9,914
81	Nov-14	12,088	(9,629)	$ 10.50	$ 35.56	$ (215,460)
82	Nov-14	-	(1,035)	$ 10.50	$ 31.27	$ (32,370)
83	Dec-14	29,632	1,188	$ 11.47	$ 38.84	$ 386,007
84	Dec-14	-	5,273	$ 11.47	$ 33.27	$ 175,437
85	Jan-15	27,068	(934)	$ 11.17	$ 37.80	$ 267,038
86	Jan-15	-	7,893	$ 11.17	$ 30.67	$ 242,101
87	Feb-15	17,101	4,916	$ 10.90	$ 36.89	$ 367,752
88	Feb-15	-	7,273	$ 10.90	$ 30.60	$ 222,576
89	Mar-15	16,862	285	$ 8.93	$ 30.23	$ 159,201
90	Mar-15	-	860	$ 8.93	$ 25.10	$ 21,582
91	Apr-15	19,746	11,326	$ 7.61	$ 25.76	$ 442,053
92	Apr-15	-	6,930	$ 7.61	$ 20.12	$ 139,449
93	May-15	11,544	(22,929)	$ 6.20	$ 21.00	$ (409,879)
94	May-15	-	(10,558)	$ 6.20	$ 13.08	$ (138,053)
95	Jun-15	15,783	(9,630)	$ 6.72	$ 22.73	$ (112,789)
96	Jun-15	-	(1,737)	$ 6.72	$ 14.57	$ (25,314)
97	Jul-15	19,235	(7,904)	$ 9.01	$ 30.49	$ (67,677)
98	Jul-15	-	6,590	$ 9.01	$ 24.50	$ 161,434
99	Aug-15	16,592	166	$ 10.03	$ 33.96	$ 172,056
100	Aug-15	-	4,228	$ 10.03	$ 27.09	$ 114,523
101	Sep-15	13,685	(1,993)	$ 9.94	$ 33.65	$ 68,955
102	Sep-15	-	2,735	$ 9.94	$ 27.90	$ 76,324
103	**Total**					**$ 2,049,434**

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS...**	$	1,919,734	$	1,994,734
6	**New Resources.....................................**	$	72,983	$	73,947
7	**Residential Exchange..........................**	$	2,847,200	$	2,846,365
8	**Conservation..**	$	156,705	$	151,235
9	**BPAPrograms......................................**	$	156,947	$	163,523
10	**Transmission..**	$	164,845	$	165,102
11	**Irrigation/Low Density Discounts.......**	$	54,119	$	55,177
12	Total..	$	5,372,533	$	5,450,084
13					
14	**Cost Allocation**				
15					
16	**FBS...**	$	1,919,734	$	1,994,734
17					
18	**Federal Base System Allocators...........**		**2014**		**2015**
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............................**		**2014**		**2015**
26	Priority Firm - 7(b) Loads.....................	$	1,919,734	$	1,994,734
27	Industrial Firm - 7(c) Loads..................	$	-	$	-
28	New Resources - 7(f) Loads..................	$	-	$	-
29	Surplus Firm - SP Loads.......................	$	-	$	-
30	Total..	$	1,919,734	$	1,994,734
31					
32					
33	**Irrigation/Low Density Discounts.......**	$	54,119	$	55,177
34					
35	**Irrigation/LDD Allocators..................**		**2014**		**2015**
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...........**		**2014**		**2015**
43	Priority Firm - 7(b) Loads.....................	$	54,119	$	55,177
44	Industrial Firm - 7(c) Loads..................	$	-	$	-
45	New Resources - 7(f) Loads..................	$	-	$	-
46	Surplus Firm - SP Loads.......................	$	-	$	-
47	Total..	$	54,119	$	55,177

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS...**	$	1,919,734	$	1,994,734
6	**New Resources.......................................**	$	72,983	$	73,947
7	**Residential Exchange.............................**	$	2,847,200	$	2,846,365
8	**Conservation...**	$	156,705	$	151,235
9	**BPAPrograms..**	$	156,947	$	163,523
10	**Transmission..**	$	164,845	$	165,102
11	**Irrigation/Low Density Discounts.........**	$	54,119	$	55,177
12	Total..	$	5,372,533	$	5,450,084
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources.......................................**	$	72,983	$	73,947
17					
18	**New Resources Allocators**		**2014**		**2015**
19	Priority Firm - 7(b) Loads.......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.....................		0.7717		0.7717
21	New Resources - 7(f) Loads....................		0.00000247		0.00000247
22	Surplus Firm - SP Loads..........................		0.2283		0.2283
23	Total..		1.0000		1.0000
24					
25	**New Resources Cost Allocation............**		**2014**		**2015**
26	Priority Firm - 7(b) Loads.......................	$	-	$	-
27	Industrial Firm - 7(c) Loads.....................	$	56,320	$	57,064
28	New Resources - 7(f) Loads....................	$	0.1805	$	0.1829
29	Surplus Firm - SP Loads..........................	$	16,663	$	16,883
30	Total..	$	72,983	$	73,947
31					
32					
33	**Residential Exchange.............................**	$	2,847,200	$	2,846,365
34	Costs Functionalized to Transmission.....	$	(194,982)	$	(194,905)
35	Costs Functionalized to Generation.........	$	2,652,218	$	2,651,459
36					
37	**Residential Exchange Allocators**		**2014**		**2015**
38	Priority Firm - 7(b) Loads.......................		0.9376		0.9372
39	Industrial Firm - 7(c) Loads.....................		0.0482		0.0485
40	New Resources - 7(f) Loads....................		0.00000015		0.00000016
41	Surplus Firm - SP Loads..........................		0.0142		0.0143
42	Total..		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2014**		**2015**
45	Priority Firm - 7(b) Loads.......................	$	2,486,730	$	2,484,944
46	Industrial Firm - 7(c) Loads.....................	$	127,705	$	128,498
47	New Resources - 7(f) Loads....................	$	0.409	$	0.412
48	Surplus Firm - SP Loads..........................	$	37,782	$	38,017
49	Total..	$	2,652,218	$	2,651,459

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS..**	$	1,919,734	$	1,994,734
6	**New Resources................................**	$	72,983	$	73,947
7	**Residential Exchange.......................**	$	2,847,200	$	2,846,365
8	**Conservation....................................**	$	156,705	$	151,235
9	**BPAPrograms..................................**	$	156,947	$	163,523
10	**Transmission...................................**	$	164,845	$	165,102
11	**Irrigation/Low Density Discounts...**	$	54,119	$	55,177
12	Total..	$	5,372,533	$	5,450,084
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	156,705	$	151,235
17					
18	**BPAPrograms..................................**	$	156,947	$	163,523
19					
20	**Transmission...................................**	$	164,845	$	165,102
21					
22					
23	**Conservation & General Allocators**		**2014**		**2015**
24	Priority Firm - 7(b) Loads.................		0.9671		0.9673
25	Industrial Firm - 7(c) Loads..............		0.0254		0.0252
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0075		0.0075
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2014**		**2015**
31	Priority Firm - 7(b) Loads.................	$	151,550	$	146,290
32	Industrial Firm - 7(c) Loads..............	$	3,978	$	3,816
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	1,177	$	1,129
35	Total..	$	156,705	$	151,235
36					
37	**BPA Programs Cost Allocation.......**		**2014**		**2015**
38	Priority Firm - 7(b) Loads.................	$	151,784	$	158,177
39	Industrial Firm - 7(c) Loads..............	$	3,984	$	4,126
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	1,179	$	1,221
42	Total..	$	156,947	$	163,523
43					
44	**Transmission Cost Allocation..........**		**2014**		**2015**
45	Priority Firm - 7(b) Loads.................	$	159,423	$	159,704
46	Industrial Firm - 7(c) Loads..............	$	4,185	$	4,166
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	1,238	$	1,232
49	Total..	$	164,845	$	165,102

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS...**	$	1,919,734	$	1,994,734
6	**New Resources.......................................**	$	72,983	$	73,947
7	**Residential Exchange............................**	$	2,847,200	$	2,846,365
8	**Conservation..**	$	156,705	$	151,235
9	**BPAPrograms..**	$	156,947	$	163,523
10	**Transmission..**	$	164,845	$	165,102
11	**Irrigation/Low Density Discounts........**	$	54,119	$	55,177
12	Total..	$	5,372,533	$	5,450,084
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2014**		**2015**
18	Priority Firm - 7(b) Loads.......................	$	4,923,339	$	4,999,027
19	Industrial Firm - 7(c) Loads....................	$	196,172	$	197,670
20	New Resources - 7(f) Loads....................	$	0.63	$	0.63
21	Surplus Firm - SP Loads.........................	$	58,039	$	58,482
22	Total Costs Functionalized to Power......	$	5,177,551	$	5,255,179
23					
24					
25					
26	REP Cost Functionalized to Transmissioı	$	194,982	$	194,905
27					
28	Total COSA Revenue Requirement	$	5,372,533	$	5,450,084

Cost of Service Analysis
General Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
5	**General Revenue Credits ($000))**		**2014**		**2015**
6					
7	**FBS**	**$**	**(117,372)**	**$**	**(113,890)**
8	Hydro and Renewable	$	(19,993)	$	(19,994)
9	Downstream Benefits and Pumping Power	$	(15,393)	$	(15,394)
10	Colville and Spokane Settlements	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)	$	-	$	-
12	Fish and Wildlife	$	(97,173)	$	(92,996)
13	4(h)(10)(c)	$	(97,173)	$	(92,996)
14	Tier 2 Adjustment	$	(206)	$	(901)
15	**Contract Obligations**	**$**	**(2,966)**	**$**	**(3,056)**
16	Pre-sub/Hungry Horse	$	(1,842)	$	(1,909)
17	Other Locational/Seasonal Exchange	$	(701)	$	(701)
18	Upper Baker	$	(422)	$	(446)
19	**New Resources**	**$**	**(1,061)**	**$**	**(1,107)**
20	Green Tags (New resources)	$	(1,061)	$	(1,107)
21	**Conservation**	**$**	**(11,859)**	**$**	**(12,083)**
22	Energy Efficiency Revenues	$	(11,859)	$	(12,083)
23	**BPAPrograms**	**$**	**-**	**$**	**-**
24	**Transmission**	**$**	**(3,225)**	**$**	**(3,240)**
25	Miscellaneous Credits (incl. GTA)	$	(3,225)	$	(3,240)
26					
27	**Other Revenue Credits ($ 000))**		**2014**		**2015**
28	Secondary Revenue	**$**	**(439,063)**	**$**	**(463,821)**
29	Incl. Slice	$	(439,063)	$	(463,821)
30	Generation Inputs for Ancillary and Other Services Revenue	**$**	**(117,696)**	**$**	**(112,910)**
31	Composite Non-Federal RSS Revenue Debit/(Credit)	**$**	**(687)**	**$**	**(958)**
32	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$**	**184**	**$**	**200**
33	Network Wind Integration & Shaping	**$**	**-**	**$**	**-**
34	**Contract Revenue from Other Long-term Sales**	**$**	**(29,163)**	**$**	**(29,163)**
35	WNP3 Settlement	$	(29,163)	$	(29,163)
36	Other Long-Term Contracts	$	-	$	-
37					
38	**Total Revenue Credits**	$	(722,908)	$	(740,028)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads.......................................	$	4,923,339	$	4,999,027
6	Industrial Firm - 7(c) Loads....................................	$	196,172	$	197,670
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	58,039	$	58,482
9	Total..	$	5,177,551	$	5,255,179
10					
11	**General Revenue Credits ($000))**		**2014**		**2015**
12					
13	**FBS..**	**$**	**(120,337)**	**$**	**(116,946)**
14	Hydro and Renewable.......................................	$	(19,993)	$	(19,994)
15	Downstream Benefits and Pumping Power..	$	(15,393)	$	(15,394)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife...	$	(97,173)	$	(92,996)
19	4(h)(10)(c)...	$	(97,173)	$	(92,996)
20	Tier 2 Adjustment..	$	(206)	$	(901)
21	Contract Obligations..	$	(2,966)	$	(3,056)
22	Pre-sub/Hungry Horse.................................	$	(1,842)	$	(1,909)
23	Other Locational/Seasonal Exchange...........	$	(701)	$	(701)
24	Upper Baker..	$	(422)	$	(446)
25					
26	**Federal Base System Allocators**		**2014**		**2015**
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**		**2014**		**2015**
34	Priority Firm - 7(b) Loads.......................................	$	(120,337)	$	(116,946)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total..	$	(120,337)	$	(116,946)
39					
40	**Allocation of Revenue Requirement**		**2014**		**2015**
41	Priority Firm - 7(b) Loads.......................................	$	4,803,002	$	4,882,081
42	Industrial Firm - 7(c) Loads....................................	$	196,172	$	197,670
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	58,039	$	58,482
45	Total..	$	5,057,214	$	5,138,233

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
40	**Allocation of Revenue Requirement**		**2014**		**2015**
41	Priority Firm - 7(b) Loads.......................................	$	4,803,002	$	4,882,081
42	Industrial Firm - 7(c) Loads....................................	$	196,172	$	197,670
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	58,039	$	58,482
45	Total...	$	5,057,214	$	5,138,233
46					
47					
48	**General Revenue Credits (/$1000))**		**2014**		**2015**
49					
50	**Transmission...**	**$**	**(3,225)**	**$**	**(3,240)**
51	Miscellaneous Credits (incl. GTA)...................	$	(3,225)	$	(3,240)
52					
53	**Conservation & General Cost Allocators**		**2014**		**2015**
54	Priority Firm - 7(b) Loads.......................................		0.9671		0.9673
55	Industrial Firm - 7(c) Loads....................................		0.0254		0.0252
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0075		0.0075
58	Total...		1.0000		1.0000
59					
60	**FBS Contract Obligation Revenue Allocation**		**2014**		**2015**
61	Priority Firm - 7(b) Loads.......................................	$	(3,119)	$	(3,134)
62	Industrial Firm - 7(c) Loads....................................	$	(82)	$	(82)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(24)	$	(24)
65	Total...	$	(3,225)	$	(3,240)
66					
67	**Allocation of Revenue Requirement**		**2014**		**2015**
68	Priority Firm - 7(b) Loads.......................................	$	4,799,883	$	4,878,947
69	Industrial Firm - 7(c) Loads....................................	$	196,091	$	197,588
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	58,014	$	58,458
72	Total...	$	5,053,989	$	5,134,993

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads................................	$	4,799,883	$	4,878,947
6	Industrial Firm - 7(c) Loads.............................	$	196,091	$	197,588
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads.................................	$	58,014	$	58,458
9	Total..	$	5,053,989	$	5,134,993
10					
11					
12	**General Revenue Credits ($000))**		**2014**		**2015**
13					
14	**New Resources...**	**$**	**(1,061)**	**$**	**(1,107)**
15	Green Tags (New resources)......................	$	(1,061)	$	(1,107)
16					
17					
18	**New Resources Cost Allocators**		**2014**		**2015**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.7717		0.7717
21	New Resources - 7(f) Loads............................		0.000002		0.000002
22	Surplus Firm - SP Loads.................................		0.2283		0.2283
23	Total..		1.0000		1.0000
24					
25	**New Resources Allocation**		**2014**		**2015**
26	Priority Firm - 7(b) Loads................................	$	-	$	-
27	Industrial Firm - 7(c) Loads.............................	$	(819)	$	(855)
28	New Resources - 7(f) Loads............................	$	(0.003)	$	(0.003)
29	Surplus Firm - SP Loads.................................	$	(242)	$	(253)
30	Total..	$	(1,061)	$	(1,107)
31					
32	**Allocation of Revenue Requirement**		**2014**		**2015**
33	Priority Firm - 7(b) Loads................................	$	4,799,883	$	4,878,947
34	Industrial Firm - 7(c) Loads.............................	$	195,271	$	196,733
35	New Resources - 7(f) Loads............................	$	0.626	$	0.631
36	Surplus Firm - SP Loads.................................	$	57,772	$	58,205
37	Total..	$	5,052,927	$	5,133,885
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
32	**Allocation of Revenue Requirement**		**2014**		**2015**
33	Priority Firm - 7(b) Loads................................	$	4,799,883	$	4,878,947
34	Industrial Firm - 7(c) Loads.............................	$	195,271	$	196,733
35	New Resources - 7(f) Loads............................	$	0.626	$	0.631
36	Surplus Firm - SP Loads.................................	$	57,772	$	58,205
37	Total...	$	5,052,927	$	5,133,885
39					
40	**General Revenue Credits (/$1000))**		**2014**		**2015**
41					
42	**Conservation..**	**$**	**(11,859)**	**$**	**(12,083)**
43	Energy Efficiency Revenues.......................	$	(11,859)	$	(12,083)
44					
45					
46	**Conservation & General Cost Allocators**		**2014**		**2015**
47	Priority Firm - 7(b) Loads................................		0.9671		0.9673
48	Industrial Firm - 7(c) Loads.............................		0.0254		0.0252
49	New Resources - 7(f) Loads............................		0.0000001		0.0000001
50	Surplus Firm - SP Loads.................................		0.0075		0.0075
51	Total...		1.0000		1.0000
52					
53	**Conservation Allocation**		**2014**		**2015**
54	Priority Firm - 7(b) Loads................................	$	(11,469)	$	(11,688)
55	Industrial Firm - 7(c) Loads.............................	$	(301)	$	(305)
56	New Resources - 7(f) Loads............................	$	(0.001)	$	(0.001)
57	Surplus Firm - SP Loads.................................	$	(89)	$	(90)
58	Total...	$	(11,859)	$	(12,083)
59					
60	**Allocation of Revenue Requirement**		**2014**		**2015**
61	Priority Firm - 7(b) Loads................................	$	4,788,414	$	4,867,259
62	Industrial Firm - 7(c) Loads.............................	$	194,970	$	196,429
63	New Resources - 7(f) Loads............................	$	0.625	$	0.630
64	Surplus Firm - SP Loads.................................	$	57,683	$	58,115
65	Total...	$	5,041,069	$	5,121,802

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads..	$	4,788,414	$	4,867,259
6	Industrial Firm - 7(c) Loads..	$	194,970	$	196,429
7	New Resources - 7(f) Loads...	$	0.6249	$	0.6296
8	Surplus Firm - SP Loads...	$	57,683	$	58,115
9	Total..	$	5,041,069	$	5,121,802
10					
11	**General Revenue Credits (/$1000))**		**2014**		**2015**
12					
13	**Generation Inputs...**	**$**	**(117,696)**	**$**	**(112,910)**
14					
15	**Network Wind Integration Shaping Revenues...............**	**$**	**-**	**$**	**-**
16					
17	**Credit Due to Idaho Deemer Account............................**	**$**	**-**	**$**	**-**
19					
20	**Conservation & General Cost Allocators**		**2014**		**2015**
21	Priority Firm - 7(b) Loads..		0.9671		0.9673
22	Industrial Firm - 7(c) Loads..		0.0254		0.0252
23	New Resources - 7(f) Loads...		0.0000001		0.0000001
24	Surplus Firm - SP Loads...		0.0075		0.0075
25	Total..		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2014**		**2015**
28	Priority Firm - 7(b) Loads..	$	(113,824)	$	(109,218)
29	Industrial Firm - 7(c) Loads..	$	(2,988)	$	(2,849)
30	New Resources - 7(f) Loads...	$	(0)	$	(0)
31	Surplus Firm - SP Loads...	$	(884)	$	(843)
32	Total..	$	(117,696)	$	(112,910)
33					
34	**Allocation of Revenue Requirement**		**2014**		**2015**
35	Priority Firm - 7(b) Loads..	$	4,674,590	$	4,758,041
36	Industrial Firm - 7(c) Loads..	$	191,983	$	193,580
37	New Resources - 7(f) Loads...	$	0.6153	$	0.6204
38	Surplus Firm - SP Loads...	$	56,799	$	57,272
39	Total..	$	4,923,373	$	5,008,893
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
34	**Allocation of Revenue Requirement**		**2014**		**2015**
35	Priority Firm - 7(b) Loads..	$	4,674,590	$	4,758,041
36	Industrial Firm - 7(c) Loads..	$	191,983	$	193,580
37	New Resources - 7(f) Loads...	$	0.6153	$	0.6204
38	Surplus Firm - SP Loads...	$	56,799	$	57,272
39	Total...	$	4,923,373	$	5,008,893
41					
42	**Other Revenue Credits**		**2014**		**2015**
43	Composite Non-Federal RSS Revenue Debit/(Credit)..	$	(687)	$	(958)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit)...	$	184	$	200
45					
46					
47	**Conservation & General Cost Allocators**		**2014**		**2015**
48	Priority Firm - 7(b) Loads..		0.9671		0.9673
49	Industrial Firm - 7(c) Loads..		0.0254		0.0252
50	New Resources - 7(f) Loads...		0.0000001		0.0000001
51	Surplus Firm - SP Loads...		0.0075		0.0075
52	Total...		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2014**		**2015**
55	Priority Firm - 7(b) Loads..	$	(487)	$	(732)
56	Industrial Firm - 7(c) Loads..	$	(13)	$	(19)
57	New Resources - 7(f) Loads...	$	(0.0000)	$	(0.0001)
58	Surplus Firm - SP Loads...	$	(4)	$	(6)
59	Total...	$	(504)	$	(757)
60					
61	**Allocation of Revenue Requirement**		**2014**		**2015**
62	Priority Firm - 7(b) Loads..	$	4,674,103	$	4,757,308
63	Industrial Firm - 7(c) Loads..	$	191,970	$	193,561
64	New Resources - 7(f) Loads...	$	0.6153	$	0.6204
65	Surplus Firm - SP Loads...	$	56,795	$	57,266
66	Total...	$	4,922,869	$	5,008,135

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2013 - September 2015
(aMW, $ 000)

	C	D		E	
4	**General Revenue Credits ($000))**		**2014**		**2015**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1661.1		1653.6
11					
12	Slice Percentage		26.6274%		26.6274%
13					
14	BPA Secondary Sales Pre-Slice, aMW (row 1 * (1-row 3))		2263.9		2253.8
15					
16	aMW to GWh Multiplier		8.760		8.760
17					
18	BPA Secondary Sales Pre-Slice GWh (row 5 * row 7)		19832.0		19742.9
19					
20	Secondary Sales Price	$	22.14	$	23.49
21	Adhoc Addition to Secondary (includes other commited sales)		-		-
22	BPA Secondary Sales Pre-Slice $000 (includes other commited sales)	$	439,063	$	463,821
23					
24	BPA Secondary Sales Allocated to 7b3 Rate Protection	$	-	$	-
25					
26	**BPA Secondary Sales Available as Revenue Credit (row 13 - row 15)**	**$**	**439,063**	**$**	**463,821**
27					
28	Slice Portion of Secondary	$	116,911	$	123,503
29					
30	**Federal Base System + NR Cost Allocators**		**2014**		**2015**
31	Priority Firm - 7(b) Loads...		0.9870		0.9874
32	Industrial Firm - 7(c) Loads...		0.0100		0.0097
33	New Resources - 7(f) Loads...		0.0000		0.0000
34	Surplus Firm - SP Loads...		0.0030		0.0029
35	Total...		1.0000		1.0000
36					
37					
38	**Allocation of Secondary Revenues Credit**		**2014**		**2015**
39	Priority Firm - 7(b) Loads...	$	(433,375)	$	(457,993)
40	Industrial Firm - 7(c) Loads...	$	(4,389)	$	(4,497)
41	New Resources - 7(f) Loads...	$	(0.0141)	$	(0.0144)
42	Surplus Firm - SP Loads...	$	(1,299)	$	(1,331)
43	Total...	$	(439,063)	$	(463,821)
44					
45	**Allocation of Revenue Requirement**		**2014**		**2015**
46	Priority Firm - 7(b) Loads...	$	4,240,728	$	4,299,315
47	Industrial Firm - 7(c) Loads...	$	187,581	$	189,063
48	New Resources - 7(f) Loads...	$	0.6012	$	0.6060
49	Surplus Firm - SP Loads...	$	55,497	$	55,935
50	Total...	$	4,483,806	$	4,544,315

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
5	**Allocation of Revenue Requirement**		2014		2015
6	Priority Firm - 7(b) Loads..	$	4,240,728	$	4,299,315
7	Industrial Firm - 7(c) Loads..	$	187,581	$	189,063
8	New Resources - 7(f) Loads...	$	0.6012	$	0.6060
9	Surplus Firm - SP Loads...	$	55,497	$	55,935
10	Total..	$	4,483,806	$	4,544,315
11					
12	**Contract Revenue from Other Long-term Sales.............**	**$**	**(29,163)**	**$**	**(29,163)**
13	WNP3 Settlement..	$	(29,163)	$	(29,163)
14	Other Long-Term Contracts....................................	$	-	$	-
15					
16	**Calculation of FPS Revenue Deficiency**		2014		2015
17	Surplus Firm - SP Loads...	$	55,497	$	55,935
18					
19	**Deficiency...**	**$**	**26,333**	**$**	**26,772**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		2014		2015
24	Priority Firm - 7(b) Loads..		0.9744		0.9746
25	Industrial Firm - 7(c) Loads..		0.0256		0.0254
26	New Resources - 7(f) Loads...		0.0000001		0.0000001
27	Surplus Firm - SP Loads...		-1.0000		-1.0000
28	Total..		0.0000		0.0000
29					
30	**Surplus Deficit Cost Allocation**		2014		2015
31	Priority Firm - 7(b) Loads..	$	25,660	$	26,091
32	Industrial Firm - 7(c) Loads..	$	674	$	681
33	New Resources - 7(f) Loads...	$	0.0022	$	0.0022
34	Surplus Firm - SP Loads...	$	(26,333)	$	(26,772)
35	Total..	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		2014		2015
39	Priority Firm - 7(b) Loads..	$	4,266,387	$	4,325,407
40	Industrial Firm - 7(c) Loads..	$	188,254	$	189,744
41	New Resources - 7(f) Loads...	$	0.6034	$	0.6082
42	Surplus Firm - SP Loads...	$	29,163	$	29,163
43	Total..	$	4,483,806	$	4,544,315

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2013 - September 2015
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2014**		**2015**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,266,387	$	4,325,407
7	Industrial Firm - 7(c) Loads...	$	188,254	$	189,744
8	New Resources - 7(f) Loads...	$	0.6034	$	0.6082
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total...	$	4,483,806	$	4,544,315
11					
12					
13	**Energy Billing Determinants (aMW)**		**2014**		**2015**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		11,900		11,976
16	Industrial Firm - 7(c) Loads...		312		312
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2014**		**2015**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		40.93		41.23
23	Industrial Firm - 7(c) Loads...		68.88		69.42
24	New Resources - 7(f) Loads...		68.88		69.42

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 7.26		
9								
10	1) Assumed DSI sale					312	aMW	
11	Assumed Wheel Turning Load					6	aMW	
12	Interruptible Load					306		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					31	MW	
15								
16	Total value of Operating Reserves per year					$ 2,665,875	per year	
17	Value converted to $/MWh on total load					$ 0.975	$/MWh	
18								
19					industrial margin	0.709		
20								
21					**net industrial margin**	**$ (0.266)**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7	HLH (mills/kWh)		31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65				
8	LLH (mills/kWh)		27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90				
9	Demand Rate ($/kW/mo)		9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2014**	
13	**2014**	HLH	4810	5471	5996	5783	5075	5318	4784	5327	4940	5269	5020	4632			Energy (GWH)	104243
14		LLH	3034	3805	4278	4071	3399	3542	3088	3659	3088	3564	3159	3133			Allocated Cost	**$ 4,344,748**
15		Demand	710	397	853	936	476	735	748	674	423	681	643	557			Rate Scalar	**11.64**
16		Revenue at marginal Rates	$ 241,791	$ 317,688	$ 385,027	$ 353,888	$ 296,386	$ 256,234	$ 191,084	$ 163,887	$ 160,107	$ 254,075	$ 262,505	$ 248,806		**$ 3,131,478**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2015**	
18	**2015**	HLH	4844	5478	6185	6036	5192	5408	4887	5184	4758	5326	5134	4489			Energy (GWH)	104908
19		LLH	3072	3899	4281	4208	3466	3591	3132	3628	2943	3415	3245	3108			Allocated Cost	**$ 4,404,675**
20		Demand	677	253	1018	933	503	729	745	493	600	681	642	565			Rate Scalar	**11.85**
21		Revenue at marginal Rates	$ 243,600	$ 319,373	$ 394,361	$ 367,638	$ 303,056	$ 260,136	$ 194,591	$ 159,352	$ 155,036	$ 252,186	$ 268,675	$ 243,393		**$ 3,161,398**		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2014**	
52	**2014**	HLH	133	123	127	129	118	132	128	127	126	127	131	122			Energy (GWH)	2733
53		LLH	98	103	104	103	92	100	97	105	97	105	101	104			Allocated Cost	**$ 109,894**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**11.37**
55		Revenue at marginal Rates	$ 6,911	$ 7,588	$ 8,404	$ 8,026	$ 7,175	$ 6,498	$ 5,246	$ 4,039	$ 4,291	$ 6,452	$ 7,199	$ 6,985		**$ 78,814**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2015**	
57	**2015**	HLH	133	123	127	129	118	132	128	127	126	127	131	122			Energy (GWH)	2733
58		LLH	98	103	104	103	92	100	97	105	97	105	101	104			Allocated Cost	**$ 110,476**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**11.58**
60		Revenue at marginal Rates	$ 6,911	$ 7,588	$ 8,404	$ 8,026	$ 7,175	$ 6,498	$ 5,246	$ 4,039	$ 4,291	$ 6,452	$ 7,199	$ 6,985		**$ 78,814**		

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2013 - September 2015
($/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQR	S
5	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
6	HLH (mills/kWh)		31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65		
7	LLH (mills/kWh)		27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90		
8	Demand Rate ($/kW/mo)		9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
9																
10																
11	**Unbifurcated PF/NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
12	**2014**	HLH	43.23	47.20	50.48	49.44	48.53	41.87	37.40	32.64	34.36	42.13	45.60	45.29		**2014**
13		LLH	39.07	42.91	44.91	42.31	42.24	36.74	31.76	24.72	26.21	36.14	38.73	39.54		**11.64**
14		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
16	**2015**	HLH	43.44	47.41	50.69	49.65	48.74	42.08	37.61	32.85	34.58	42.34	45.81	45.50		**2015**
17		LLH	39.28	43.12	45.12	42.52	42.45	36.95	31.97	24.93	26.42	36.35	38.94	39.75		**11.85**
18		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		**Scalar**
36																
42																
43		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
44	**2014**	HLH	42.96	46.93	50.22	49.17	48.26	41.60	37.13	32.37	34.10	41.86	45.33	45.02		**2014**
45		LLH	38.80	42.64	44.64	42.04	41.97	36.47	31.49	24.45	25.94	35.87	38.46	39.27		**11.37**
46		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		**Scalar**
47			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		
48	**2015**	HLH	43.17	47.14	50.43	49.39	48.47	41.82	37.35	32.58	34.31	42.07	45.54	45.24		**2015**
49		LLH	39.01	42.85	44.85	42.25	42.18	36.68	31.70	24.66	26.15	36.08	38.67	39.48		**11.58**
50		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		**Scalar**

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2013 - September 2015
($ 000)

	B	C	D	E	F	G	H
4						**FY 2014**	**FY 2015**
5							
6	1	IP Allocated Costs				188,254	189,744
7	2	IP Revenues @ Net Margin				(728)	(728)
8	3	adjustment				1,272	1,395
9	4	IP Marginal Cost Rate Revenues				78,814	78,814
10	5	PF/NR Marginal Cost Rate Revenues				3,131,478	3,161,398
11	6	PF/NR Allocated Energy Costs				4,266,388	4,325,407
12	7	Numerator: 1-2-3-((4/5)*6)				80,333	81,244
13	8						
14	9	PF Allocation Factor for Delta				0.999999916	0.999999916
15	10	NR Allocation Factor for Delta				0.000000084	0.000000084
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0252	1.0249
18	13						
19	14	DELTA: (7/12)				**78,360**	**79,268**
20							
21						-0.267	-0.267
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2013 - September 2015
($ 000, aMW, $/MWh)

	B		C		D
5	**Initial Allocation of Net Revenue Requirement)**		**2014**		**2015**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,266,387	$	4,325,407
7	Industrial Firm - 7(c) Loads...	$	188,254	$	189,744
8	New Resources - 7(f) Loads..	$	0.6034	$	0.6082
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total..	$	4,483,806	$	4,544,315
11					
12					
13	**First IP-PF Link Delta**	**$**	**78,360**	**$**	**79,268**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2014**		**2015**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999916		0.999999916
18	Industrial Firm - 7(c) Loads...		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads..		0.000000084		0.000000084
20					
21	**7(c)(2) Delta Cost Allocation**		**2014**		**2015**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	78,360	$	79,268
23	Industrial Firm - 7(c) Loads...	$	(78,360)	$	(79,268)
24	New Resources - 7(f) Loads..	$	0.007	$	0.007
25	Total..	$	(0)	$	0
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2014**		**2015**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,344,748	$	4,404,675
29	Industrial Firm - 7(c) Loads...	$	109,894	$	110,476
30	New Resources - 7(f) Loads..	$	0.610	$	0.615
31	Surplus Firm - SP Loads..	$	29,163	$	29,163
32	Total..	$	4,483,806	$	4,544,315
33					
34	**Energy Billing Determinants (aMW)**		**2014**		**2015**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		11,900		11,976
36	Industrial Firm - 7(c) Loads...		312.0003992		312.0003992
37	New Resources - 7(f) Loads..		0.001		0.001
38					
39					
40	**Average Power Rates ($/MWh)**		**2014**		**2015**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		41.68		41.99
43	Industrial Firm - 7(c) Loads...		40.21		40.42
44	New Resources - 7(f) Loads..		69.63		70.18
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**41.83**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2013 - September 2015

	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]		3,112	4,337	3,176	2,290	7,449	5,466
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		14,378	9,584	46,684	27,944	54,674	153,264
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]		28.04					
36	20	Floor Rate (mills/kWh)[8]		20.91					
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 2013 - September 2015

	B	C	D	E	F	G	H	I	J
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				5,466			
20	2	Floor Rate (mills/kWh)				20.91			
21	3	Value of Reserves Credit (mills/kWh)							
22	4	Revenue at Floor Rate Less VOR Credit				114,302	114,302	20.91	
23	5	IP Revenue Under Proposed Rates					220,370	40.31	
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 2013 - September 2015

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2014**	**2015**	Total
10		Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,344,748	$ 4,404,675	$ 8,749,422
11					
12		**Energy Billing Determinants (aMW)**	**2014**	**2015**	
13		Unbifurcated Priority Firm - 7(b) Loads..............................	11,900	11,976	
14					
15					
16		**Average Power Rates**	**2014**	**2015**	
17					
18		Unbifurcated Priority Firm - 7(b) Loads..............................	41.68	41.99	
25					
26			(GWh)		
27		Two Year PF Public Load T1	121501		
28		Two Year PF Public Load T2	815		
29		Two Year IOU PF Exchange Load	81771		
30		Two Year COU PF Exchange Load	5064		
31		Total Two-Year Unbifurcated PF Load	209151		
32					
33					
34		T 2 Costs	$ 31,271		
35		T 1 Costs	$ 8,718,151		
36		Total	$ 8,749,422		
37					
45		Total PF Costs Minus PF T2 Costs	$ 8,718,151		
46		Total PF Load Minus PF T2 Load	208,336		
47		COU Base PF w/o Transmission	41.85		
48		Exchange Transmission Adder	4.49		
49		**COU Base PFx**	**46.34**		
50					
51					
52		Two Year COU PF Exchange Load	5064		
53		Two Year Base PF Public Exchange T2 Revenue	$ 211,892		
54					
55		Total PF Costs Minus COU PFx Revenue	$ 8,537,530		
56		Total PF Loads Minus COU PFx Loads	204,087		
57		IOU Base PF w/o Transmission	41.83		
58		Exchange Transmission Adder	4.49		
59		**IOU Base PFx**	**46.32**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2013 - September 2015

	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		$197,500		
19	Refund Amount*		$76,538		
20	REP Recovery Amount		$274,038		
21					
26					
27					
28			**2014**		**2015**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	824,108	$	824,108
31	REP Recovery Amount	**$**	**274,038**	**$**	**274,038**
32	Rate Protection Delta	$	550,070	$	550,070
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 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**46.32**									
6	**COU Base PFx**	**46.34**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2014**	**2015**		**2014**	**2015**		**2014**	**2015**
9											
10											
11	Avista Corporation	1		57.05	57.05		3,868	3,868		$ 41,488	$ 41,488
12	Idaho Power Company	1		50.22	50.22		6,427	6,427		$ 25,048	$ 25,048
13	NorthWestern Energy,	1		70.65	70.65		668	668		$ 16,255	$ 16,255
14	PacifiCorp	1		65.61	65.61		9,235	9,235		$ 178,121	$ 178,121
15	Portland General Elect	1		68.99	68.99		8,664	8,664		$ 196,381	$ 196,381
16	Puget Sound Energy, I	1		76.83	76.83		12,024	12,024		$ 366,814	$ 366,814
17	Clark Public Utilities	1		49.91	49.91		2,540	2,523		$ 9,078	$ 9,016
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish County PU	0		45.27	45.27		0	0		$ -	$ -
31	Total									**$ 833,186**	**$ 833,124**
32											
33									IOU	**$ 824,108**	**$ 824,108**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY 2014**	**FY 2015**	**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	57.05	46.32	3,868	3,868	3,868	$ 41,488			$ 27,692	$ 3,853	8.16	54.48	$ 9,943
9	Idaho Power Company	1	50.22	46.32	6,427	6,427	6,427	$ 25,048			$ 16,719	$ 2,326	2.96	49.29	$ 6,003
10	NorthWestern Energy, LLC	1	70.65	46.32	668	668	668	$ 16,255			$ 10,850	$ 1,510	18.50	64.82	$ 3,896
11	PacifiCorp	1	65.61	46.32	9,235	9,235	9,235	$ 178,121			$ 118,891	$ 16,543	14.67	60.99	$ 42,687
12	Portland General Electric Company	1	68.99	46.32	8,664	8,664	8,664	$ 196,381			$ 131,079	$ 18,239	17.23	63.56	$ 47,063
13	Puget Sound	1	76.83	46.32	12,024	12,024	12,024	$ 366,814			$ 244,839	$ 34,067	23.20	69.52	$ 87,908
14	Clark Public Utilities	1	49.91	46.34	2,540	2,523	2,532	$ 9,047			$ 6,039		2.39	48.72	$ 3,008
15	Franklin	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish County PUD No 1	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
17	Total							$ 833,155	$197,500	$76,538	$ 556,109	$76,538			$ 200,508
18															
19	rounding to 4 places = $75						IOU Σ(g)	$ 824,108	$197,500	$274,038	$ 550,070	IOU Σ(j)		IOU REP	$ 197,500
20							COU Σ(g)	$ 9,047		$3,008	$ 6,039	COU Σ(j)		COU REP	$ 3,008
21															
22	**IOU Reallocations**														
23			**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2014**	**FY 2015**
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		$ 9,943	$ 2,005	$ 116	$ 8,054	$ 33,435	8.64	54.9677		$ 8,053		Avista	$ 8,053	$ 8,053
28	Idaho Power Company		$ 6,003	$ 3,001	$ -	$ 3,001	$ 22,047	3.43	49.7530		$ 3,001		Idaho Power	$ 3,001	$ 3,001
29	NorthWestern Energy, LLC		$ 3,896	$ (766)	$ 402	$ 5,063	$ 11,192	16.75	63.0722		$ 5,063		NorthWestern	$ 5,063	$ 5,063
30	PacifiCorp		$ 42,687	$ 8,443	$ 496	$ 34,740	$ 143,380	15.53	61.8482		$ 34,741		PacifiCorp	$ 34,741	$ 34,741
31	Portland General Electric Company		$ 47,063	$ 1,238	$ 4,087	$ 49,913	$ 146,468	16.91	63.2288		$ 49,913		Portland	$ 49,913	$ 49,913
32	Puget Sound		$ 87,908	$ -	$ 8,820	$ 96,728	$ 270,086	22.46	68.7853		$ 96,728		Puget Sound	$ 96,728	$ 96,728
33	Total		$ 197,500	$ 13,920	$ 13,920	$ 197,500	$ 626,608				$ 197,500		IOU REP	$ 197,500	$ 197,500
34															
35													Clark	$ 3,019	$ 2,998
36													Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ -	$ -
38			Avista Corporati	o Power Com	Western Energy	PacifiCorp	eneral Electri	Puget Sound	Total				COU REP	$ 3,019	$ 2,998
39			$ 2,005	$ 3,001	$ (766)	$ 8,443	$ 1,238	$ -					Total REP	$ 200,519	$ 200,498
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			$ 156	$ (41)				$ 116				Refund Amt	$ 76,538	$ 76,538
42	Idaho Power Company								$ -				REP Cost	$ 277,056	$ 277,036
43	NorthWestern Energy, LLC		$ 56	$ 56		$ 237	$ 53	$ -	$ 402						
44	PacifiCorp			$ 670	$ (174)				$ 496						
45	Portland General Electric Company		$ 679	$ 739	$ (192)	$ 2,861			$ 4,087						
46	Puget Sound		$ 1,269	$ 1,380	$ (359)	$ 5,345	$ 1,185		$ 8,820						
47			$ 2,005	$ 3,001	$ (766)	$ 8,443	$ 1,238	$ -	$ 13,920						

Rate Directive Step
IOU Reallocation Balances
Test Period October 2013 - September 2015

	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 2013 - September 2015

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2014**		**2015**
5	Priority Firm Public - 7(b) Loads...	$	2,534,798	$	2,582,112
6	Priority Firm Exchange - 7(b) Loads....................................	$	1,809,950	$	1,822,563
7	Industrial Firm - 7(c) Loads...	$	109,894	$	110,476
8	New Resources - 7(f) Loads...	$	0.610	$	0.615
9	Surplus Firm - SP Loads...	$	29,163	$	29,163
10	Total..	$	4,483,806	$	4,544,315
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2014**		**2015**
14	Unconstrained Benefits	$	833,186	$	833,124
15	REP Recovery Amount plus COU Benefits	$	(277,056)	$	(277,036)
16	delta	$	556,129	$	556,088
17					
18					
19	**Allocation Factors**		**2014**		**2015**
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**		**2014**		**2015**
27	Priority Firm Public - 7(b) Loads...	$	(556,129)	$	(556,088)
28	Priority Firm Exchange - 7(b) Loads....................................	$	556,129	$	556,088
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2014**		**2015**
35	Priority Firm Public - 7(b) Loads...	$	1,978,668	$	2,026,024
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,366,079	$	2,378,651
37	Industrial Firm - 7(c) Loads...	$	109,894	$	110,476
38	New Resources - 7(f) Loads...	$	0.610	$	0.615
39	Surplus Firm - SP Loads...	$	29,163	$	29,163
40	Total..	$	4,483,806	$	4,544,315
41					
42					
43	**Energy Billing Determinants (aMW)**		**2014**		**2015**
44	Priority Firm Public - 7(b) Loads...		6,943		7,020
45	Priority Firm Exchange - 7(b) Loads....................................		4,957		4,955
46	Industrial Firm - 7(c) Loads...		312		312
47	New Resources - 7(f) Loads...		0.001		0.001
48					
50					
51	**Average Power Rates**		**2014**		**2015**
52	Priority Firm Public - 7(b) Loads...		32.54		32.94
53	Priority Firm Exchange - 7(b) Loads....................................		58.98		59.29
54	Industrial Firm - 7(c) Loads...		40.21		40.42
55	New Resources - 7(f) Loads...		69.63		70.18

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2013 - September 2015

	B	C		D	
25			**2014**		**2015**
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	$	7.69	$	7.69
30	IP Load		2,733		2,733
31	NR Load		0		0
32	REP Surharge Revenue from IP Rate	$	21,021	$	21,019
33	REP Surharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surchar	$	256,035	$	256,016
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.03	$	3.99
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	32,032	$	31,913
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	20,094	$	20,101
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2014**		**2015**
48	Priority Firm Public - 7(b) Loads..	$	245,024	$	245,123
49	Industrial Firm - 7(c) Loads...	$	32,032	$	31,913
50	New Resources - 7(f) Loads...	$	0.103	$	0.102
51		$	277,056	$	277,036
52					
53	Adjustment Necessary to Achieve Reallocation		**2014**		**2015**
54	Priority Firm Public - 7(b) Loads..	$	(20,094)	$	(20,101)
55	Industrial Firm - 7(c) Loads...	$	20,094	$	20,101
56	New Resources - 7(f) Loads...	$	0.064	$	0.064
57		$	(0)	$	(0)
58					
59			**2014**		**2015**
60	PF Contribution to Net REP Benefits $/MWh..........................		4.03		3.99
61	IP Contribution to Net REP Benefits $/MWh...........................		11.72		11.68
62	NR Contribution to Net REP Benefits $/MWh..........................		11.72		11.68

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2013 - September 2015

	B	C	D
4	**Cost Allocation After Rate Protection Provided by PFx**	**2014**	**2015**
5	Priority Firm Public - 7(b) Loads	$ 1,978,668	$ 2,026,024
6	Priority Firm Exchange - 7(b) Loads	$ 2,366,079	$ 2,378,651
7	Industrial Firm - 7(c) Loads	$ 109,894	$ 110,476
8	New Resources - 7(f) Loads	$ 0.610	$ 0.615
9	Surplus Firm - SP Loads	$ 29,163	$ 29,163
10	Total	$ 4,483,806	$ 4,544,315
11			
12			
13			
14	**Allocation of Rate Protection Provided by IP and NR**	**2014**	**2015**
15	Priority Firm Public - 7(b) Loads	$ (20,094)	$ (20,101)
16			
17	Industrial Firm - 7(c) Loads	$ 20,094	$ 20,101
18	New Resources - 7(f) Loads	$ 0.064	$ 0.064
19	Total	$ (0)	$ (0)
20			
21			
22	**Cost Allocation After Rate Protection Provided by IP and NR**	**2014**	**2015**
23	Priority Firm Public - 7(b) Loads	$ 1,958,574	$ 2,005,922
24	Priority Firm Exchange - 7(b) Loads	$ 2,366,079	$ 2,378,651
25	Industrial Firm - 7(c) Loads	$ 129,988	$ 130,577
26	New Resources - 7(f) Loads	$ 0.674	$ 0.679
27	Surplus Firm - SP Loads	$ 29,163	$ 29,163
28	Total	$ 4,483,806	$ 4,544,315
29			
30			
31	**Energy Billing Determinants (aMW)**	**2014**	**2015**
32	Priority Firm Public - 7(b) Loads	6,943	7,020
33	Priority Firm Exchange - 7(b) Loads	4,957	4,955
34	Industrial Firm - 7(c) Loads	312	312
35	New Resources - 7(f) Loads	0.001	0.001
36			
38			
39	**Average Power Rates After Rate Protection Reallocations**	**2014**	**2015**
40	Priority Firm Public - 7(b) Loads	32.20	32.62
41	Priority Firm Exchange - 7(b) Loads	58.98	59.29
42	Industrial Firm - 7(c) Loads	47.56	47.78
43	New Resources - 7(f) Loads	76.98	77.54

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
5																			
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**					
7	HLH (mills/kWh)		31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65					
8	LLH (mills/kWh)		27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90					
9	Demand Rate ($/kW/mo)		9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94					
10																			
11		**PF+NR Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2014**	
12	**2014**	HLH	2806	3192	3498	3374	2961	3103	2791	3108	2882	3074	2929	2702				Energy (GWH)	60817
13		LLH	1770	2220	2496	2375	1983	2066	1802	2135	1802	2079	1843	1828				Allocated Cost	$ 1,982,468
14		Demand	414	232	498	546	278	429	437	393	247	397	375	325				Rate Scalar	**2.56**
15	Revenue at marginal Rates		$ 141,065	$ 185,344	$ 224,631	$ 206,464	$ 172,917	$ 149,491	$ 111,482	$ 95,614	$ 93,409	$ 148,232	$ 153,150	$ 145,158			$ 1,826,956		
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2015**	
17	**2015**	HLH	2840	3212	3626	3538	3044	3171	2865	3039	2789	3122	3010	2631				Energy (GWH)	61499
18		LLH	1801	2286	2510	2467	2032	2105	1836	2127	1725	2002	1902	1822				Allocated Cost	$ 2,029,562
19		Demand	397	148	597	547	295	427	437	289	352	399	376	331				Rate Scalar	**2.87**
20	Revenue at marginal Rates		$ 142,804	$ 187,223	$ 231,183	$ 215,517	$ 177,658	$ 152,497	$ 114,074	$ 93,415	$ 90,885	$ 147,837	$ 157,503	$ 142,682			$ 1,853,277		
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**				**2014**	
26	**2014**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
27		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	$ 106,095
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**9.98**
29	Revenue at marginal Rates		$ 6,911	$ 7,588	$ 8,404	$ 8,026	$ 7,175	$ 6,498	$ 5,246	$ 4,039	$ 4,291	$ 6,452	$ 7,199	$ 6,985			$ 78,814		
30			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2015**	
31	**2015**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
32		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	$ 106,938
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**10.29**
34	Revenue at marginal Rates		$ 6,911	$ 7,588	$ 8,404	$ 8,026	$ 7,175	$ 6,498	$ 5,246	$ 4,039	$ 4,291	$ 6,452	$ 7,199	$ 6,985			$ 78,814		
35																			

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2013 - Septmentber 2015

	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)		31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65				
7	LLH (mills/kWh)		27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90				
8	Demand Rate ($/kW/mo)		9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				
9																		
10																		
11	**Unbifurcated PF /NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2014**	HLH	34.15	38.12	41.40	40.36	39.44	32.79	28.32	23.55	25.28	33.05	36.52	36.21				**2014**
13		LLH	29.99	33.83	35.83	33.23	33.16	27.66	22.68	15.64	17.13	27.06	29.65	30.46				**2.56**
14		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2015**	HLH	34.46	38.43	41.71	40.67	39.75	33.10	28.63	23.86	25.59	33.35	36.83	36.52				**2015**
17		LLH	30.30	34.14	36.14	33.54	33.47	27.97	22.99	15.95	17.44	27.37	29.96	30.77				**2.87**
18		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2014**	HLH	41.57	45.54	48.83	47.78	46.87	40.21	35.74	30.98	32.71	40.47	43.94	43.63				**2010**
23		LLH	37.41	41.25	43.25	40.65	40.58	35.08	30.10	23.06	24.55	34.48	37.07	37.88				**9.98**
24		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2015**	HLH	41.88	45.85	49.13	48.09	47.18	40.52	36.05	31.29	33.02	40.78	44.25	43.94				**2011**
27		LLH	37.72	41.56	43.56	40.96	40.89	35.39	30.41	23.37	24.86	34.79	37.38	38.19				**10.29**
28		Demand	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94				**Scalar**

Table 2.4.18

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H
4						**FY 2014**	**FY 2015**
5							
6	1	IP Allocated Costs				109,894	110,476
7	2	IP Revenues @ Net Margin				(728)	(728)
8	3	adjustment				1,206	1,254
9	4	IP Marginal Cost Rate Revenues				78,814	78,814
10	5	PF/NR Marginal Cost Rate Revenues				1,826,956	1,853,277
11	6	PF Allocated Energy Costs				1,958,575	2,005,923
12	7	Numerator: 1-2-3-((4/5)*6)				24,924	24,644
13	8						
14	9	PF Allocation Factor for Delta				0.999999916	0.999999916
15	10	NR Allocation Factor for Delta				0.000000084	0.000000084
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0431	1.0425
18	13						
19	14	DELTA: (7/12)				**23,893**	**23,639**
20							
21						-0.267	-0.267
22							

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2013 - September 2015

	B	C		D		E
4	**Cost Allocation After Rate Protection Provided by IP and NR**		**2014**		**2015**	
5	Priority Firm Public - 7(b) Loads..	$	1,958,574	$	2,005,922	
6	Priority Firm Exchange - 7(b) Loads...	$	2,366,079	$	2,378,651	
7	Industrial Firm - 7(c) Loads..	$	129,988	$	130,577	
8	New Resources - 7(f) Loads..	$	0.674	$	0.679	
9	Surplus Firm - SP Loads...	$	29,163	$	29,163	
10	Total...	$	4,483,806	$	4,544,315	
11						
12						
13	IP-PF Link Delta..	$	23,893	$	23,639	
14						
15			**2014**		**2015**	
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**		**2014**		**2015**	
22	Priority Firm Public - 7(b) Loads..	$	23,893	$	23,639	
23	Priority Firm Exchange - 7(b) Loads...	$	-	$	-	
24	Industrial Firm - 7(c) Loads..	$	(23,893)	$	(23,639)	
25	New Resources - 7(f) Loads..	$	0.003	$	0.003	
26	Total...	$	(0)	$	0	
27						
28						
29	**Cost Allocation After Second IP-PF Link**		**2014**		**2015**	
30	Priority Firm Public - 7(b) Loads..	$	1,982,467	$	2,029,561	
31	Priority Firm Exchange - 7(b) Loads...	$	2,366,079	$	2,378,651	
32	Industrial Firm - 7(c) Loads..	$	106,095	$	106,938	
33	New Resources - 7(f) Loads..	$	0.678	$	0.683	
34	Surplus Firm - SP Loads...	$	29,163	$	29,163	
35	Total...	$	4,483,806	$	4,544,315	
36						
37						
38	**Energy Billing Determinants (aMW)**		**2014**		**2015**	
39	Priority Firm Public - 7(b) Loads..		6,943		7,020	
40	Priority Firm Exchange - 7(b) Loads...		4,957		4,955	
41	Industrial Firm - 7(c) Loads..		312		312	
42	New Resources - 7(f) Loads..		0.001		0.001	
43						
45						
46	**Average Power Rates After Second IP-PF Link**		**2014**		**2015**	Average
47	Priority Firm Public - 7(b) Loads..		32.60		33.00	**32.80**
48	Priority Firm Exchange - 7(b) Loads...		58.98		59.29	**59.13**
49	Industrial Firm - 7(c) Loads..		38.82		39.13	**38.97**
50	New Resources - 7(f) Loads..		77.38		77.92	**77.65**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2013 to September 2015

	B	D	E	F	G	H	I	J	K	L
4		**2014**	**2015**	**Avg**				**2014**	**2015**	**Avg**
5	Resource Costs	2,844,827	2,843,969	2,844,398			PFx Alloc Cost	(2,366,079)	(2,378,651)	
6	PFx Revenues	(2,561,062)	(2,573,556)	(2,567,309)			Exch Tmn Cost	(194,982)	(194,905)	
7	REP Benefits	283,765	270,413	277,089				(2,561,062)	(2,573,556)	(2,567,309)
8										
9	**REP Benefits**						**PFx Revenues**			
10	Avista Corporation	8,053	8,053				Avista Corporation	212,590	212,590	
11	Idaho Power Company	3,001	3,001				Idaho Power Company	319,772	319,772	
12	NorthWestern Energy, LLC	5,063	5,063				NorthWestern Energy, LLC	42,145	42,145	
13	PacifiCorp	34,741	34,741				PacifiCorp	571,177	571,177	
14	Portland General Electric Company	49,913	49,913				Portland General Electric Compa	547,792	547,792	
15	Puget Sound Energy, Inc.	96,728	96,728				Puget Sound Energy, Inc.	827,062	827,062	
16	IOU REP	197,500	197,500	197,500			IOU REP	2,520,537	2,520,537	2,520,537
17										
18	Clark Public Utilities	3,019	2,998				Clark Public Utilities	123,771	122,934	
19	Franklin	-	-				Franklin	-	-	
20	Snohomish County PUD No 1	-	-				Snohomish County PUD No 1	-	-	
21	COU REP	3,019	2,998	3,008			COU REP	123,771	122,934	123,353
22										
23	Refund Amounts	76,538	76,538				Refund Amounts	(76,538)	(76,538)	
24	Total REP	277,056	277,036	277,046			Total REP	2,567,771	2,566,933	2,567,352
25				(43)				6,709	(6,623)	43
26										
27	**For Slice True-Up**									100.00%
28	IOU REP	197,500	197,500							
29	COU REP	3,019	2,998							
30	Refund Amounts	76,538	76,538							
31	Total REP	277,056	277,036							

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	F	G	H
4						AggregationKey	**2014**	**2015**
5		**Composite**						
6			Federal Base System					
7				Hydro				
8					Operating Expense	CFHYOP	540,858	556,404
9					Interest	IFHYIT	184,010	192,202
10					MRNR	MFHYMR	-	-
11				Fish & Wildlife				
12					Operating Expense	CFFWOP	296,288	305,464
13					Interest	IFFWIT	19,842	20,328
14					MRNR	MFFWMR	-	-
15				Trojan		CFTR	1,500	1,500
16				WNP #1		CFW1	248,943	185,264
17				Columbia Generating Station		CFCG	388,527	419,194
18				WNP #3		CFW3	165,601	166,975
19				Augmentation		Internal	6,199	94,914
20			Residentail Exchange Program					
21				REP Net Cost		Internal	2,844,827	2,843,969
22				REP Net Cost		Internal	(2,561,062)	(2,573,556)
23				Program Support		CRSP	973	996
24				Settlement Interest Accrual		CRST	1,400	1,400
25			NewResources					
26				Cowlitz		CNCZ	10,286	10,317
27				Idaho		CNID	4,648	4,880
28				Tier 1 Aug (Klondike III)		CNTA	12,513	12,510
29				Other		CNOT	48,049	48,753
30			Conservation					
31				Operating Expense		CCOP	135,694	129,508
32				Interest		ICIT	21,011	21,727
33				MRNR		MCMR	-	-
34			BPAPrograms					
35				Operating Expense		CBOP	153,988	160,789
36				Interest		IBIT	2,959	2,734
37				MRNR		MBMR	-	-
39			Transmission					
40				Transmission and Ancillary Services		CTTA	47,750	48,706
41				General Transfer Agreements		CTGA	55,533	56,578
42			Nonslice Interest and MRNR Allocated to Cost Pools					
43				Interest on BPA fund Credit to Nonslice		Internal	930	(124)
44				Accrual Revenue (MRNR Adjustment)		Internal	(3,524)	(3,524)
45			**Total**			Internal	**2,627,742**	**2,707,908**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	F	G	H
4						AggregationKey	**2014**	**2015**
46		**Non-Slice**						
47			FBS					
48				Balancing Purchases from Risk Mod		Internal	27,421	26,720
49				Balancing in Revenue Requirement		NFBL	35,044	-
50				PNRR				
51					Hydro	NFHYPR	-	-
52					Fish & Wildlife	NFFWPR	-	-
53			Conservation					
54				PNRR		NCPR	-	-
55			BPAPrograms					
56				Hedging Mitigation		NBHM	-	-
57				Bad Debt		NBOP	-	-
58				PNRR		NBPR	-	-
59			Transmission					
60				Transmission and Ancillary Services		NTTA	59,274	57,485
61				Third-party T&A		NT3A	2,288	2,333
62			Nonslice Interest and MRNR					
63				BPA Fund		NIBF	(930)	124
64				Non-Slice MRNR Adjustment		NMAJ	3,524	3,524
65			**Total**			Internal	**126,621**	**90,186**
66		**Slice**						
67			BPAPrograms					
68				Other Slice Costs		SBSW	-	-
69			**Total**			Internal	-	-
70		**Tier 2**						
71			FBS					
72				Tier 2 Purchase Costs		2FT2PC	5,296	24,869
73				Tier 2 Rate Design Adjustments		2FT2RD	206	901
74				Tier 2 Other Costs		2FT2OT	-	-
75			**Total**			Internal	**5,502**	**25,769**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	F	G	H
4						AggregationKey	**2014**	**2015**
76		**Rate Direct/Design Adjustments**						
77			Credits Allocated Against Cost Pools					
78				FBS (excluding T2 Adjustment)			(117,166)	(112,990)
79				Contract Obligations			(2,264)	(2,355)
80				New Resources			(1,061)	(1,107)
81				Conservation			(11,859)	(12,083)
82				BPAPrograms			-	-
83				Transmission			(3,225)	(3,240)
84								
85			Secondary Energy Credit (includes pre-sale)			Internal	(439,063)	(463,821)
86			Generation Inputs Credit			CDGI	(117,696)	(112,910)
87			Network Wind Credit			NDWI	-	-
88			Composite revenues associated with firm surplus sales			CDFC	(29,163)	(29,163)
89			Non-slice revenues associated with firm surplus sales			NDFC	(701)	(701)
90								
91			Low Density Discount			Internal	35,303	36,361
92			Irrigation Rate Mitigation Costs			Internal	18,816	18,816
93								
94			Composite Augmentation RSS Revenue Debit/(Credit)			CD2RCF	(1,972)	(1,972)
95			Composite Tier 2 RSS Revenue Debit/(Credit)			2D2RCF	(23)	(99)
96			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			2D2DC	(182)	(802)
97			Composite Non-Federal RSS Revenue Debit/(Credit)			CD2RCN	(687)	(958)
98			Non-Slice Augmentation RSC Revenue Debit/(Credit)			ND2RNF	(541)	(541)
99			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			2D2RNF	-	-
100			Non-Slice Tier 2 Rate Design Debit/(Credit)			2D2DN	-	-
101			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			ND2RNN	184	200
102								
103			Firm Surplus and Secondary Credit (from unused RHWM)			Internal	(3,299)	(2,383)
104			Demand Revenue			Internal	42,954	43,388
105			Load Shaping Revenue			Internal	3,422	22,791
106								

Table 2.5.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2013 to September 2015

	B	C		D	
4			**2014**		**2015**
5	Secondary (aMW)		2,264		2,254
6	T1SFCO (aMW)		7,059		7,059
7	RHWM Augmentation (aMW)		57		57
8	RP Augmentation (aMW)		-		-
9	System Augmentation (aMW)		21		318
10	Augmentation Base (aMW)		78		375
11	IP and NR Loads contributing to avoided cost		321		321
12					
13	Value of Secondary	$	22.14	$	23.49
14	Value of T1SFCO ($/MWh)	$	29.20	$	29.20
15	Value of Augmentation	$	33.47	$	34.08
16					
17	Secondary (MWh)		19,832,019		19,742,927
18	T1SFCO (MWh)		61,835,360		61,835,360
19	RHWM Augmentation (MWh)		499,670		499,670
20	Augmentation Base (MWh)		684,857		3,285,000
21	IP and NR Loads (MWh)		2,812,443		2,812,443
22					
23	Unused RHWM (MWh)		1,176,642		916,026
24					
25	Unused Secondary		374,351		290,126
26	Unused T1SFCO		1,167,210		908,683
27	Unused Augmentation		9,432		7,343
28					
29	Value of Unused	$	42,684,341	$	33,598,367
30	Value of System Augmentation not Purchased	$	39,385,288	$	31,214,888
31					
32	Net Credit/(Cost)	$	3,299,053	$	2,383,479
33					
34	$/MWh value of Unused RHWM	**$**	**36.45**		

Table 2.5.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
5	Non Slice Loads (MWh)	44,086,919	44,985,840
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	837,651	854,731
8	Average Slice&Non-Slice Tier 1 Rate	32.77	32.77
9	Implied Cost/Credit ($1000)	27,450	28,010

Table 2.5.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2013 - September 2015

	A	B	C	E	F	G
4				**2014**	**2015**	
5		**Table 3.1**				
6			Regulated	6,575	6,450	
7			Independent	353	353	
8		**Table 3.2**				
9			Ashland Solar Project	0	0	
10			Columbia Generating Station	1,030	878	
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	0	0	
16			Foote Creek 4	4	4	
17			Fourmile Hill Geothermal	-	-	
18			Georgia-Pacific Paper (Wauna)	19	19	
19			Glines Canyon Hydro	-	-	
20			Klondike I	7	7	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	136	136	
24			Libby Coordination	33	33	
25			BC Hydro Power Purchase	1	1	
26			Pasadena Capacity	1	0	
27			Pasadena Seasonal	2	2	
28			Pasadena Exchange Energy	2	2	
29			PacifiCorp (So Idaho)	-	-	
30			Riverside Capacity	5	5	
31			Riverside Seasonal	7	7	
32			Riverside Exchange Energy	7	7	
33			Sierra Pacific (Wells)	-	-	
34			PacifiCorp	15	-	
35		**Table 3.4**				
36			USBR Pump Load	180	180	
37			Canadian Entitlement	484	465	
38			Non-Treaty Storage	10	10	
39			Libby Coordination	32	32	
40			Hungry Horse	7	7	
41			Riverside Capacity	5	5	
42			Riverside Seasonal	7	7	
43			Pasadena Capacity	1	-	
44			Pasadena Seasonal	3	3	
45			Sierra Pacific (Wells)	-	-	
46			Intertie Losses	0.5	0.4	
47			WNP3	83	83	
48			PacifiCorp	-	-	
49			PacifiCorp (So Idaho)	-	-	
50			Upper Baker	1	1	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	6,983	7,062	
55			Tier 2	18	75	
56			Net Preference	6,966	6,987	
57			Industrial	312	312	
58			New Resource	0	0	
59			Intraregional Transfer	92	92	
60			FBS Obligation	716	697	
61			Seasonal or Capacity Exchange	70	70	
62			Conservation Augmentation	(30)	(30)	
63			Transmission Losses Before Slice Return	236	236	
64			Slice Return of Losses	36	35	
65			Transmission Losses After Slice Return	199	201	
66						
67		**Annual T1SFCO**		7,213	6,937	
68		**RHWM Process T1SFCO (annual)**		7,183	6,935	
69		**Difference**		30	2	
70		**Augmentation Price (Secondary in the case Augmentation is zero)**		$ 33.47	$ 34.08	
71		**Hours**		8,760	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ 8,836,926	$ 592,796	

Table 2.5.5

Rate Design Step
Calculation of Load Shaping and Demand Revenuest
Test Period October 2013 - September 2015

	B	E	F	G	H	I	J	K	L
5	**2014**	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-13	414,281	$ 9.33	$ 3,865,239	(134,034)	135,568	$ 31.59	$ 27.43	$ (515,507)
7	Nov-13	231,725	$ 10.50	$ 2,433,113	(288,696)	117,707	$ 35.56	$ 31.27	$ (6,585,349)
8	Dec-13	497,878	$ 11.47	$ 5,710,663	56,604	370,263	$ 38.84	$ 33.27	$ 14,517,152
9	Jan-14	545,873	$ 11.17	$ 6,097,405	30,769	452,455	$ 37.80	$ 30.67	$ 15,039,846
10	Feb-14	277,505	$ 10.90	$ 3,024,807	217,949	371,149	$ 36.89	$ 30.60	$ 19,397,298
11	Mar-14	428,851	$ 8.93	$ 3,829,640	157,996	247,116	$ 30.23	$ 25.10	$ 10,978,832
12	Apr-14	436,524	$ 7.61	$ 3,321,945	493,964	354,154	$ 25.76	$ 20.12	$ 19,850,075
13	May-14	393,447	$ 6.20	$ 2,439,374	(1,090,273)	(489,307)	$ 21.00	$ 13.08	$ (29,295,862)
14	Jun-14	246,843	$ 6.72	$ 1,658,785	(691,177)	(153,660)	$ 22.73	$ 14.57	$ (17,949,286)
15	Jul-14	397,336	$ 9.01	$ 3,579,998	(649,793)	101,867	$ 30.49	$ 24.50	$ (17,316,430)
16	Aug-14	375,055	$ 10.03	$ 3,761,798	(247,554)	128,286	$ 33.96	$ 27.09	$ (4,931,679)
17	Sep-14	325,095	$ 9.94	$ 3,231,449	(126,011)	160,336	$ 33.65	$ 27.90	$ 233,112
18	**Total**			**$ 42,954,216**					**$ 3,422,202**
19									
20	**2015**	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-14	396,974	$ 9.33	$ 3,703,763	(108,123)	154,679	$ 31.59	$ 27.43	$ 827,245
22	Nov-14	148,227	$ 10.50	$ 1,556,383	(296,263)	182,905	$ 35.56	$ 31.27	$ (4,815,652)
23	Dec-14	596,970	$ 11.47	$ 6,847,243	140,172	361,531	$ 38.84	$ 33.27	$ 17,472,405
24	Jan-15	546,930	$ 11.17	$ 6,109,203	77,500	490,889	$ 37.80	$ 30.67	$ 17,985,050
25	Feb-15	294,699	$ 10.90	$ 3,212,217	261,027	403,519	$ 36.89	$ 30.60	$ 21,976,958
26	Mar-15	427,479	$ 8.93	$ 3,817,390	192,398	273,036	$ 30.23	$ 25.10	$ 12,669,386
27	Apr-15	436,951	$ 7.61	$ 3,325,194	525,249	376,063	$ 25.76	$ 20.12	$ 21,096,789
28	May-15	288,912	$ 6.20	$ 1,791,253	(1,100,658)	(446,577)	$ 21.00	$ 13.08	$ (28,955,043)
29	Jun-15	351,831	$ 6.72	$ 2,364,303	(648,110)	(166,623)	$ 22.73	$ 14.57	$ (17,159,230)
30	Jul-15	399,422	$ 9.01	$ 3,598,791	(626,861)	122,275	$ 30.49	$ 24.50	$ (16,117,231)
31	Aug-15	376,079	$ 10.03	$ 3,772,069	(225,004)	145,803	$ 33.96	$ 27.09	$ (3,691,307)
32	Sep-15	331,021	$ 9.94	$ 3,290,348	(103,440)	178,587	$ 33.65	$ 27.90	$ 1,501,826
33	**Total**			**$ 43,388,157**					**$ 22,791,196**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B	C		D		E	
5	**Costs ($000)**		**2014**		**2015**	**Rate Period**	
6	**Composite..........**	$	2,627,742	$	2,707,908	$	5,335,650
7	**Non-Slice..........**	$	126,621	$	90,186	$	216,807
8	**Slice..........**	$	-	$	-	$	-
9	**Tier 2..........**	$	5,502	$	25,769	$	31,271
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2014**		**2015**	**Rate Period**	
15	DSI Revenue Credit..........	**$**	**(106,510)**	**$**	**(106,510)**	**$**	**(213,020)**
16	Exchange Revenues..........	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues..........	**$**	**(0.68)**	**$**	**(0.68)**	**$**	**(1)**
18	FPS Revenues..........	$	(29,163)	$	(29,163)	$	(58,327)
19	Non-Federal RSS Revenues..........	$	(687)	$	(958)	$	(1,645)
20	Other Credits..........	$	(253,271)	$	(244,684)	$	(497,956)
21	Tiered Rate Elements..........					$	-
22	Unused RHWM Credit Reallocation..........	$	(3,299)	$	(2,383)	$	(5,683)
23	Balancing Augmentation Adjustment Reallocation..........	$	24,714	$	(4,995)	$	19,719
24	Composite Augmentation RSS Revenue Debit/(Credit)...	$	(1,972)	$	(1,972)	$	(3,944)
25	Composite Tier 2 RSS Revenue Debit/(Credit)..........	$	(23)	$	(99)	$	(122)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$	(182)	$	(802)	$	(984)
27	Transmission Losses Adjustment Reallocation..........	$	(27,450)	$	(28,010)	$	(55,459)
28	Total..........	$	(397,845)	$	(419,576)	$	(817,422)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2014**		**2015**	**Rate Period**	
31	Irigation Rate Discout Costs..........	$	18,816	$	18,816	$	37,632
32	Low Density Discount Costs..........	$	35,303	$	36,361	$	71,665
33	Total..........	$	54,119	$	55,177	$	109,297
34							
35			**2014**		**2015**	**Rate Period**	
36	**Composite..........**	$	2,284,016	$	2,343,509	$	4,627,525

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B	C		D		E	
5	**Costs ($000)**		**2014**		**2015**	**Rate Period**	
6	**Composite..**	$	2,627,742	$	2,707,908	$	5,335,650
7	**Non-Slice..**	$	126,621	$	90,186	$	216,807
8	**Slice..**	$	-	$	-	$	-
9	**Tier 2...**	$	5,502	$	25,769	$	31,271
37							
38	**Non-Slice Revenues, Credits, and Costs**		**2014**		**2015**	**Rate Period**	
39	Secondary Revenue...	$	(322,152)	$	(340,317)	$	(662,469)
40	Unused RHWM Credit Reallocation................................	$	3,299	$	2,383	$	5,683
41	FPS Revenues not classified as Obligations in TRM..........	$	(701)	$	(701)	$	(1,402)
42	Non-federal RSC Revenues..	$	184	$	200	$	384
43	Network Wind Integration..	$	-	$	-	$	-
44	Load Shaping Revenue...	$	(3,422)	$	(22,791)	$	(26,213)
45	Balancing Augmentation Adjustment Reallocation..........	$	(24,714)	$	4,995	$	(19,719)
46	Demand Revenue..	$	(42,954)	$	(43,388)	$	(86,342)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)......	$	(541)	$	(541)	$	(1,082)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)..................	$	-	$	-	$	-
49	Non-Slice Tier 2 Rate Design Debit/(Credit).....................	$	-	$	-	$	-
50	Transmission Losses Adjustment Reallocation..................	$	27,450	$	28,010	$	55,459
51	Total...	$	(363,552)	$	(372,151)	$	(735,702)
52							
53			**2014**		**2015**	**Rate Period**	
54	**Non-Slice..**	$	(236,931)	$	(281,964)	$	(518,895)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B	C		D		E	
5	**Costs ($000)**		**2014**		**2015**	**Rate Period**	
6	**Composite.......**	$	2,627,742	$	2,707,908	$	5,335,650
7	**Non-Slice.......**	$	126,621	$	90,186	$	216,807
8	**Slice.......**	$	-	$	-	$	-
9	**Tier 2.......**	$	5,502	$	25,769	$	31,271
55							
56	**TRM Costs after Adjustments**		**2014**		**2015**	**Rate Period**	
57	**Composite.......**	$	2,284,016	$	2,343,509	$	4,627,525
58	**Non-Slice.......**	$	(236,931)	$	(281,964)	$	(518,895)
59	**Slice.......**	$	-	$	-	$	-
60	**Tier 2.......**	$	5,502	$	25,769	$	31,271
61	**Total Costs**	$	2,052,587	$	2,087,314	$	4,139,901
62							
63	**Billing Determinants**		**2014**		**2015**	**Rate Period**	
64	**TOCA.......**		98.1124		98.5305		98.3214
65	**Non-slice TOCA.......**		71.4850		71.9031		71.6940
66	**Slice Percentage.......**		26.6274		26.6274		26.6274
67							
68	**Annual TRM Rates ($000/percent)**		**2014**		**2015**	**Rate Period**	
69	**Composite.......**	$	23,280	$	23,785	$	23,533
70	**Non-Slice.......**	$	(3,314)	$	(3,921)	$	(3,619)
71	**Slice.......**	$	-	$	-	$	-
72							
73	**Monthly TRM Rates ($/percent)**		**2014**		**2015**	**Rate Period**	
74	**Composite.......**		1,939,966		1,982,051		1,961,053
75	**Non-Slice.......**		(276,201)		(326,788)		(301,568)
76	**Slice.......**		-		-		-
77							
78	**Tier 2 Rates ($/MWh)**		**2014**		**2015**	**Rate Period**	
79	**Tier 2 Short Term.......**	$	35.58	$	39.65	$	37.62
80	**Tier 2 Load Growth.......**	$	35.58	$	41.62	$	41.62
81	**Tier 2 Vintage 2014.......**	$	-	$	41.56	$	41.56

Table 2.5.7.1

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2013 - September 2015
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2014	2015		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													122,316	5,466	0.01752
14	Federal Base System														
15	Hydro		724,868	748,606		1,473,474	0.0	0.0	0				12.05	0.00	0.00
16	Fish & Wildlife		316,130	325,792		641,922	0.0	0.0	0				5.25	0.00	0.00
17	Trojan		1,500	1,500		3,000	0.0	0.0	0				0.03	0.00	0.00
18	WNP #1		248,943	185,264		434,207	0.0	0.0	0				3.55	0.00	0.00
19	WNP #2		388,527	419,194		807,721	0.0	0.0	0				6.60	0.00	0.00
20	WNP #3		165,601	166,975		332,576	0.0	0.0	0				2.72	0.00	0.00
21	System Augmentation		6,199	94,914		101,113	0.0	0.0	0				0.83	0.00	0.00
22	Balancing Power Purchases		62,464	26,720		89,184	0.0	0.0	0				0.73	0.00	0.00
23	Tier 2 Costs		5,502	25,769		31,271	0.0	0.0	0				0.26	0.00	0.00
24	Total Federal Base System		1,919,734	1,994,734		3,914,468	0.0	0.0	0.0				32.00	0.00	0.00
25															
26	New Resources		72,983	73,947		146,930	0.0	0.0	0		PFx Revenue		1.20	0.00	0.00
27	Residential Exchange		2,652,218	2,651,459		558,947	0.0	0.0	0		4,744,730		4.57	0.00	0.00
28	Conservation		156,705	151,235		307,940	0.0	0.0	0				2.52	0.00	0.00
29	BPA Programs & Transmission		321,792	328,625		650,417	0.0	0.0	0		NR Revenue		5.32	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,123,432	5,200,001		5,578,703	0	0	0		1.4		45.61	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(439,063)	(463,821)		(902,884)	0.0	0.0	0.0				-7.38	0.00	0.00
34	LDD/IRD Expense		54,119	55,177		109,297	0.0						0.89	0.00	0.00
35	Other Revenue Credits		(254,682)	(247,043)		(501,725)	0.0	0.0	0.0				-4.10	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(58,327)	0	0.0	58,327				-0.48	0.00	0.00
38						(1.4)		1.3604					0.00	0.00	77.65
39	IP Rate Revenue		0	0		(213,031)	213,031						-1.74	38.97	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(639,626)	(655,687)		(1,566,672)	213,031	1.4	58,327				-12.81	38.97	77.65
42															
43	Total Generation		4,483,806	4,544,315									**32.80**	**38.97**	**77.65**
44				**PFp Revenue Recovery**		**4,012,031**	213,031	1.4	58,327						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2013 to September 30, 2015

	B	C	D	E	F	G
4						
5						
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**				
7						
8			2014	2015		
9		Composite Revenue..............................	$ 2,308,843	$ 2,318,682		
10		Non-Slice Revenue...............................	$ (258,691)	$ (260,204)		
11		Slice Revenue..	$ -	$ -		
12		Tier 2..	$ 5,502	$ 25,769		
13		Load Shaping Revenue.........................	$ 3,422	$ 22,791		
14		Demand Revenue.................................	$ 42,954	$ 43,388		
15		Total TRM PF Revenue	$ 2,102,030	$ 2,150,427		
16						
17		Slice Portion of Secondary Revenue......	$ (116,911)	$ (123,503)		
18		Total Net TRM PF Revenue	$ 1,985,119	$ 2,026,923		
19						
20					PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF		$ 4,012,042	32.80	
22						
23		w/ Slice PF Public Rate Revenue from "Net REP" Table		**$ 4,012,031**	32.80	
24			delta	$ (12)		
25						
26						

Table 2.5.8.1

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65		
16	LLH (mills/kWh)	27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90		
17	Demand Rate ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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)	5,606	6,367	7,086	6,873	5,968	6,235	5,618	6,109	5,633	6,157	5,900	5,296		121,501
22	LLH (GWh)	3,542	4,474	4,975	4,811	3,988	4,141	3,609	4,230	3,498	4,051	3,714	3,620		Tier 1 Demand (MW/mo)
23	Demand (MW)	811	380	1,095	1,093	572	856	873	682	599	797	751	656		9,166
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)	$ 177,083	$ 226,419	$ 275,229	$ 259,817	$ 220,160	$ 188,478	$ 144,720	$ 128,271	$ 128,013	$ 187,720	$ 200,353	$ 178,237	$	3,570,378
29	LLH ($000)	$ 97,151	$ 139,907	$ 165,510	$ 147,559	$ 122,039	$ 103,930	$ 72,622	$ 55,326	$ 50,969	$ 99,242	$ 100,625	$ 100,998		Demand Revenue ($000)
30	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522	$	86,342
31														$	3,656,721
32															Tier 1 Revenue Requirement (RR) ($000)
33														$	3,980,758
34															Tier 1 RR less Demand Revenue ($000)
35														$	3,894,415
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)	34.26	38.23	41.51	40.47	39.56	32.90	28.43	23.67	25.40	33.16	36.63	36.32		(2.67)
38	LLH (mills/kWh)	30.10	33.94	35.94	33.34	33.27	27.77	22.79	15.75	17.24	27.17	29.76	30.57		
39	Demand ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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)	$ 192,050	$ 243,427	$ 294,122	$ 278,162	$ 236,110	$ 205,121	$ 159,711	$ 144,597	$ 143,077	$ 204,173	$ 216,111	$ 192,364	$	3,894,809
45	LLH ($000)	$ 106,608	$ 151,853	$ 178,793	$ 160,405	$ 132,688	$ 114,986	$ 82,259	$ 66,620	$ 60,309	$ 110,057	$ 110,543	$ 110,664		Allocated Cost Demand ($000)
46	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522	$	86,342
47														$	3,981,151
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,894,809	32.06												
51	Allocated Cost Demand	$ 86,342	0.71												
52	Total Allocated Costs	$ 3,981,151	32.77												
53															
54	Tier 1 Energy (GWh)		121,501												
55	Market Energy Delta (mills/kWh)		(2.67)												

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65		
16	LLH (mills/kWh)	27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90		
17	Demand Rate ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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)	5,646	6,403	7,124	6,912	6,004	6,273	5,656	6,146	5,671	6,196	5,939	5,334		122,316
22	LLH (GWh)	3,571	4,505	5,006	4,842	4,015	4,171	3,638	4,262	3,527	4,081	3,745	3,650		Tier 1 Demand (MW/mo)
23	Demand (MW)	811	380	1,095	1,093	572	856	873	682	599	797	751	656		9,166
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)	$ 178,352	$ 227,699	$ 276,721	$ 261,279	$ 221,478	$ 189,648	$ 145,717	$ 129,058	$ 128,886	$ 188,900	$ 201,667	$ 179,489		$ 3,593,891
29	LLH ($000)	$ 97,947	$ 140,879	$ 166,535	$ 148,495	$ 122,859	$ 104,694	$ 73,191	$ 55,741	$ 51,385	$ 99,989	$ 101,451	$ 101,829		Demand Revenue ($000)
30	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522		$ 86,342
31															$ 3,680,233
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,012,029
34															T1&2RR less Demand Revenue ($000)
35															$ 3,925,687
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)	34.30	38.27	41.55	40.51	39.60	32.94	28.47	23.71	25.44	33.20	36.67	36.36		(2.71)
38	LLH (mills/kWh)	30.14	33.98	35.98	33.38	33.31	27.81	22.83	15.79	17.28	27.21	29.80	30.61		
39	Demand ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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)	$ 193,652	$ 245,060	$ 296,002	$ 280,005	$ 237,764	$ 206,645	$ 161,037	$ 145,730	$ 144,280	$ 205,704	$ 217,766	$ 193,929		$ 3,925,390
45	LLH ($000)	$ 107,624	$ 153,088	$ 180,100	$ 161,616	$ 133,740	$ 115,997	$ 83,049	$ 67,290	$ 60,943	$ 111,049	$ 111,600	$ 111,720		Allocated Cost Demand ($000)
46	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522		$ 86,342
47															$ 4,011,732
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,925,390	32.09												
51	Allocated Cost Demand	$ 86,342	0.71												
52	Total Allocated Costs	$ 4,011,732	32.80												
53															
54	Tier 1&2 Energy (GWh)		122,316												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(2.71)												

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2013 - September 2015

PF Melded Equiv Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14
HLH (mills/kWh)	34.30	38.27	41.55	40.51	39.60	32.94	28.47	23.71	25.44	33.20	36.67	36.36
LLH (mills/kWh)	30.14	33.98	35.98	33.38	33.31	27.81	22.83	15.79	17.28	27.21	29.80	30.61
Demand Rate ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (GWh)	267	246	255	257	237	265	257	254	253	254	263	243
LLH (GWh)	197	206	208	206	183	199	193	210	195	211	202	207
Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-

Totals	
IP Energy (GWh)	5,466

Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH ($000)	$ 9,141	$ 9,410	$ 10,582	$ 10,418	$ 9,381	$ 8,714	$ 7,303	$ 6,018	$ 6,428	$ 8,435	$ 9,638	$ 8,839
LLH ($000)	$ 5,938	$ 6,990	$ 7,478	$ 6,891	$ 6,109	$ 5,538	$ 4,407	$ 3,318	$ 3,367	$ 5,729	$ 6,020	$ 6,351
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Energy Rev & Tier1&2 ($000)	$ 172,442
Demand Rev ($000)	$ -
	$ 172,442
VOR	(0.98)
Industrial Margin (mills/kWh)	0.709
Net industrial Margin	(0.266)
Settlement Charge	**7.691**

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78
LLH (mills/kWh)	37.56	41.40	43.40	40.80	40.73	35.23	30.25	23.21	24.70	34.63	37.22	38.03
Demand ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH ($000)	$ 11,119	$ 11,234	$ 12,472	$ 12,327	$ 11,138	$ 10,677	$ 9,207	$ 7,901	$ 8,303	$ 10,321	$ 11,588	$ 10,642
LLH ($000)	$ 7,399	$ 8,517	$ 9,020	$ 8,422	$ 7,470	$ 7,015	$ 5,839	$ 4,878	$ 4,812	$ 7,291	$ 7,518	$ 7,891
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Allocated Cost Energy ($000)	$ 213,002
Allocated Cost Demand ($000)	$ -
	$ 213,002

Average IP Rate	($000)	(mills/kWh)
Allocated Cost Energy	$ 213,002	38.97
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 213,002	38.97
IP Energy (GWh)		5,466
Industrial Margin (mills/kWh)		0.71
VOR		(0.98)
Settlement Charge		7.69

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65		
16	LLH (mills/kWh)	27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90		
17	Demand Rate ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0007	0.0007	0.0007	0.0006	0.0007	0.0006	0.0007	0.0006	0.0007	0.0007	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)	$ 0.0273	$ 0.0279	$ 0.0317	$ 0.0315	$ 0.0283	$ 0.0252	$ 0.0214	$ 0.0171	$ 0.0185	$ 0.0254	$ 0.0283	$ 0.0269		$ 0.5055
29	LLH ($000)	$ 0.0171	$ 0.0206	$ 0.0224	$ 0.0201	$ 0.0176	$ 0.0164	$ 0.0122	$ 0.0088	$ 0.0091	$ 0.0161	$ 0.0178	$ 0.0179		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.5055
32															NR Revenue Requirement (RR) ($000)
33															$ 1.3604
34															NR RR less Demand Revenue ($000)
35															$ 1.3604
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	80.39	84.36	87.64	86.60	85.69	79.03	74.56	69.80	71.53	79.29	82.76	82.45		(48.80)
38	LLH (mills/kWh)	76.23	80.07	82.07	79.47	79.40	73.90	68.92	61.88	63.37	73.30	75.89	76.70		
39	Demand ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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)	$ 0.0695	$ 0.0661	$ 0.0715	$ 0.0721	$ 0.0658	$ 0.0658	$ 0.0620	$ 0.0570	$ 0.0584	$ 0.0660	$ 0.0689	$ 0.0660		$ 1.3605
45	LLH ($000)	$ 0.0476	$ 0.0527	$ 0.0552	$ 0.0521	$ 0.0457	$ 0.0483	$ 0.0419	$ 0.0416	$ 0.0395	$ 0.0481	$ 0.0498	$ 0.0491		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.3605
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.3605	77.65												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.3605	77.65												
53															
54		NR Energy (GWh)	0.0175												
55															

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.59	35.56	38.84	37.80	36.89	30.23	25.76	21.00	22.73	30.49	33.96	33.65		
16	LLH (mills/kWh)	27.43	31.27	33.27	30.67	30.60	25.10	20.12	13.08	14.57	24.50	27.09	27.90		
17	Demand Rate ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
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]	4,043	4,494	5,270	5,323	4,652	4,581	4,066	3,745	3,777	4,214	4,227	3,862		89,073
22	LLH (GWh) [FMDT1L]	2,666	3,379	3,890	3,913	3,229	3,182	2,725	2,754	2,492	3,004	2,830	2,756		Tier 1 Demand (MW/mo)
23	Demand (MW)	811	380	1,095	1,093	572	856	873	682	599	797	751	656		9,166
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000) [MktR]
28	HLH ($000)	$ 127,714	$ 159,817	$ 204,710	$ 201,228	$ 171,614	$ 138,486	$ 104,736	$ 78,640	$ 85,824	$ 128,477	$ 143,561	$ 129,959		$ 2,635,927
29	LLH ($000)	$ 73,116	$ 105,665	$ 129,407	$ 120,007	$ 98,808	$ 79,865	$ 54,826	$ 36,022	$ 36,303	$ 73,591	$ 76,659	$ 76,892		Demand Revenue ($000)
30	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522		$ 86,342
31															$ 2,722,269
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															**$ 2,967,988**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 2,881,646
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)	34.35	38.32	41.60	40.56	39.65	32.99	28.52	23.76	25.49	33.25	36.72	36.41		(2.76)
38	LLH (mills/kWh)	30.19	34.03	36.03	33.43	33.36	27.86	22.88	15.84	17.33	27.26	29.85	30.66		
39	Demand ($/kW/mo)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94		
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 138,872	$ 172,227	$ 219,237	$ 215,916	$ 184,466	$ 151,127	$ 115,950	$ 88,986	$ 96,263	$ 140,116	$ 155,233	$ 140,608		$ 2,881,780
45	LLH ($000)	$ 80,473	$ 114,991	$ 140,143	$ 130,807	$ 107,720	$ 88,647	$ 62,346	$ 43,624	$ 43,180	$ 81,881	$ 84,469	$ 84,499		Allocated Cost Demand ($000)
46	Demand ($000)	$ 7,569	$ 3,989	$ 12,558	$ 12,207	$ 6,237	$ 7,647	$ 6,647	$ 4,231	$ 4,023	$ 7,179	$ 7,534	$ 6,522		$ 86,342
47															$ 2,968,122
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 2,881,780	32.35												
51	Allocated Cost Demand	$ 86,342	0.97												
52	Total Allocated Costs	$ 2,968,122	33.32												
54	Tier 1 Energy (GWh) [FAT1L]		89,073												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(2.76)												

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2013 - September 2015

	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	1,473,474	7.045	16.84%		861,722	7.045	611,752	7.045	
19		Fish & Wildlife	641,922	3.069	7.34%		375,411	3.069	266,511	3.069	
20		Trojan	3,000	0.014	0.03%		1,754	0.014	1,246	0.014	
21		WNP #1	434,207	2.076	4.96%		253,934	2.076	180,273	2.076	
22		WNP #2	807,721	3.862	9.23%		472,374	3.862	335,347	3.862	
23		WNP #3	332,576	1.590	3.80%		194,498	1.590	138,078	1.590	
24		System Augmentation	101,113	0.483	1.16%		59,133	0.483	41,980	0.483	
25		Balancing Power Purchases	89,184	0.426	1.02%		52,157	0.426	37,027	0.426	
26		Tier 2 Costs	31,271	0.150	0.36%		18,288	0.150	12,983	0.150	
27		Total Federal Base System	3,914,468	18.716	44.74%		2,289,272	18.716	1,625,197	18.716	
28		New Resources									
29		Gross Residential Exchange	4,971,674	23.771	56.82%		2,907,550	23.771	2,064,124	23.771	
30		Conservation	297,840	1.424	3.40%		174,184	1.424	123,656	1.424	
31		BPA Programs	309,960	1.482	3.54%		181,272	1.482	128,688	1.482	
32		Power Transmission	319,126	1.526	3.65%		186,632	1.526	132,494	1.526	
33		TOTAL COSA ALLOCATIONS	9,813,069	46.919	112.16%		5,738,910	46.919	4,074,160	46.919	
34											
35											
36		Nonfirm Excess Revenue Credit	(891,368)	-4.262	-10.19%		(521,293)	-4.262	(370,076)	-4.262	
37		Low Density Discount Expense	109,297	0.523	1.25%		63,919	0.523	45,377	0.523	
38		Other Revenue Credits	(490,955)	-2.347	-5.61%		(287,122)	-2.347	(203,833)	-2.347	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	51,751	0.247	0.59%		30,265	0.247	21,486	0.247	
41		7(c)(2) Delta Adjustment	157,628	0.754	1.80%		92,185	0.754	65,444	0.754	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,063,647)	-5.086	-12.16%		(622,045)	-5.086	(441,602)	-5.086	
44											
45		Total Generation	8,749,422	**41.8331**	100.00%		5,116,864	**41.83**	3,632,558	**41.83**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,152,413)	-9.422	1,112,217	1,112,217	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					47,533	0.389			
50		Total Generation					**4,011,984**	**32.80**	4,744,775	**54.64**	
51											
52		Total Transmission							389,887	4.490	
53									5,134,663	**59.13**	
54											

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2013 - September 2015

	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	113,384	20.743	53.23%
28	Gross Residential Exchange	256,204	46.870	120.27%
29	Conservation	7,794	1.426	3.66%
30	BPA Programs	8,110	1.484	3.81%
31	Power Transmission	8,351	1.528	3.92%
32	TOTAL COSA ALLOCATIONS	393,842	72.050	184.89%
33				
34	Nonfirm Excess Revenue Credit	(8,886)	-1.626	-4.17%
35				
36	Other Revenue Credits	(8,312)	-1.521	-3.90%
37				
38	SP Revenue Surplus/Dfct Adj.	1,354	0.248	0.64%
39	7(c)(2) Delta Adjustment	(157,628)	-28.837	-74.00%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(173,472)	-31.735	-81.43%
42	Total Generation	220,370	40.315	103.45%
43				
55	Total Allocated & Adjusted Costs	220,370	40.315	103.45%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	40,196	7.353	18.87%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(47,533)	-8.696	-22.31%
60		213,033	**38.97**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	5,466		

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2013 - September 2015

	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	0.3634	20.743	26.71%
27	Gross Residential Exchange	0.8212	46.870	60.36%
28	Conservation	0.0250	1.426	1.84%
29	BPA Programs	0.0528	3.011	3.88%
30	TOTAL COSA ALLOCATIONS	1.2623	72.050	92.79%
31				
32	Nonfirm Excess Revenue Credit	(0.0285)	-1.626	-2.09%
33				
34	Other Revenue Credits	(0.0266)	-1.521	-1.96%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0043	0.248	0.32%
37	7(c)(2) Delta Adjustment	0.0132	0.755	0.97%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0376)	-2.144	-2.76%
40	Total Generation Energy	1.2248	69.906	90.03%
41				
50				
51	Total Allocated & Adjusted Costs	1.2248	69.906	90.03%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1288	7.353	9.47%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0068	0.389	0.50%
55				
56	Total With 7(b)(2) Adjustments	1.3604	**77.65**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01752		

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2013 - September 2015

	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	2,289,272	2,907,550		5,196,821		44.05%	55.95%		100.00%
18	Priority Firm - Exchange	1,625,197	2,064,124		3,689,321		44.05%	55.95%		100.00%
19	Priority Firm Power - Total	3,914,468	4,971,674		8,886,142		44.05%	55.95%		100.00%
20	Industrial Firm Power		256,204	113,384	369,587			69.32%	30.68%	100.00%
21	New Resources Firm		0.821	0	1			69.32%	30.68%	100.00%
22	Firm Power Products and Services		75,799	33,545	109,345			69.32%	30.68%	100.00%
23										
24										
25	**TOTALS**	**3,914,468**	**5,303,678**	**146,930**	**9,365,076**		**41.80%**	**56.63%**	**1.57%**	**100.00%**
26										
27					214,617					
28										
29				Average Cost of Resources	43.64					
30										
31				Average Cost to Serve Load Growth	39.86					

SECTION 3: RATE DESIGN

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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.

Table 3.2 Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.3 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.

Table 3.4 Tier 1 Demand Rates
Table shows calculation of the Tier 1 Demand rate.

Table 3.5 Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.6 Tier 2 Rate Inputs
Table lists TSS Rates, prices used for Tier 2 surplus credit or deficit debit, and amounts of remarketed power used to meet Tier 2 obligations.

Table 3.7 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.

Table 3.8 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 3.9 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 3.10 Tier 2 VR1-2014 Rate Costing Table
Costing table used to calculate the VR1-2014 rates for each year of the rate period.

Table 3.11 Tier 2 Purchases Made by BPA
Table lists information pertaining to Mid-C purchases made by BPA to meet load served at a Tier 2 rate obligations.

Table 3.12 Total Remarketing Charges and Credits
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.

Table 3.13 Tier 2 Load Obligations
Table lists Tier 2 load obligation by Tier 2 rate and year. Also includes load obligation after accounting for transmission losses when delivering Tier 2-priced power to loads.

Table 3.14 Customers Receiving a VR1-2014 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2014 purchases and their associated credits.

Table 3.15 Customers Receiving a Load Growth Billing Adjustment
List of Load Growth rate customers and their billing adjustments.

Table 3.16 Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' CHWM.

Table 3.17 Rates and Charges for RSS and Related Services in FY 2014 and FY 2015
Table summarizes the RSS model forecast results for the purchasers' 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 $/MWh equivalent rate for the identified services.

Table 3.18 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 3.19 Transmission Scheduling Service OATI Registration-Fee Customer List
List of customers with TSS that must pay the OATI registration fee. Applies only to year or years customers use TSS.

Table 3.20 Customers Receiving Resource Remarketing Service Credits
List of customers with Resource Remarketing Service for their non-Federal resources and their associated credits.

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	AggregationKey	Category	2014	2015	2016	2017	2018	2019
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	2,512.8	2,512.8	2,512.8	2,512.8	2,512.8	2,512.8
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	-1,971.9	-1,971.9	-1,971.9	-1,971.9	-1,971.9	-1,971.9
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	687.3	-957.5	-957.5	-957.5	-957.5	-957.5
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	-541.0	-541.0	-541.0	-541.0	-541.0	-541.0
7	2.0	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
8	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	183.7	200.4	200.4	200.4	200.4	200.4

Table 3.2

Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		BP-14			
2		FY2014		FY2015	
3	Line Item	FY2014	Total Forecast Sales (MWh)	FY2015	Total Forecast Sales (MWh)
4	Executive and Administrative Services	$ 4,157,033	80,550,067	$ 4,360,146	81,167,448
5	Generation Project Coordination	$ 6,826,271		$ 6,968,124	
6	Sales & Support	$ 20,950,525		$ 21,338,766	
7	Strategy, Finance & Risk Mgmt	$ 18,299,293		$ 19,373,348	
8	Agency Services G&A	$ 44,815,176		$ 46,493,765	

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-13	30.76	26.89		October	31.59	27.43
4	Nov-13	34.86	30.75		November	35.56	31.27
5	Dec-13	38.58	33.29		December	38.84	33.27
6	Jan-14	37.71	30.94		January	37.80	30.67
7	Feb-14	37.19	31.07		February	36.89	30.60
8	Mar-14	30.86	25.76		March	30.23	25.10
9	Apr-14	26.08	20.60		April	25.76	20.12
10	May-14	21.30	13.66		May	21.00	13.08
11	Jun-14	22.39	14.39		June	22.73	14.57
12	Jul-14	30.22	24.55		July	30.49	24.50
13	Aug-14	33.58	26.90		August	33.96	27.09
14	Sep-14	33.86	28.13		September	33.65	27.90
15	Oct-14	32.43	27.97				
16	Nov-14	36.26	31.79				$/MWh
17	Dec-14	39.11	33.24		FY2014 Aurora Flat Annual Block		28.84
18	Jan-15	37.89	30.41		FY2015 Aurora Flat Annual Block		28.86
19	Feb-15	36.59	30.13				
20	Mar-15	29.60	24.43				
21	Apr-15	25.44	19.64				
22	May-15	20.70	12.49				
23	Jun-15	23.07	14.75				
24	Jul-15	30.75	24.44				
25	Aug-15	34.34	27.27				
26	Sep-15	33.45	27.68				

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)	2014		2007	106.23		Oct	31.59	8.35%	$ 9.33
3	Cost of Debt	4.04%	/1	2008	108.58		Nov	35.56	9.39%	$ 10.50
4				2009	109.53		Dec	38.84	10.26%	$ 11.47
5	Inflation Rate	1.67%		2010	110.99		Jan	37.80	9.99%	$ 11.17
6	Insurance Rate	0.25%	/2	2011	113.36		Feb	36.89	9.75%	$ 10.90
7				2012	115.39		Mar	30.23	7.99%	$ 8.93
8	Debt Finance Period (years)	30	/2				Apr	25.76	6.81%	$ 7.61
9	Plant Lifecycle (years)	30	/2		101.67%	5-year Ave.	May	21.00	5.55%	$ 6.20
10							Jun	22.73	6.01%	$ 6.72
11	Plant in service 2014 Vintaged Heat Rate Btu/kWh	8,650	/2	IPD from			Jul	30.49	8.06%	$ 9.01
12							Aug	33.96	8.97%	$ 10.03
13	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2				Sep	33.65	8.89%	$ 9.94
14	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 45.95	/2					Average $/kW/mo		$ 9.32
15	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 38.47								
16	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 52.45								
17	Average of Existing and New with 10000 Heat Rate 2014$	$ 45.46								
18	Average of Existing and New with 8650 Heat Rate 2014$	$ 39.32								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,105.00	/2	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21	Fixed O&M $/kW/yr 2014$	$ 9.13	/3	2014	$ 1,086.58	$64.21	$ 9.13	$ 2.72	$ 35.39	$ 111.45
22	Fixed Fuel adjusted for 10% capacity release credit $/kW/yr	$ 35.39		2015	$ 1,049.75	$64.21	$ 9.28	$ 2.62	$ 35.98	$ 112.10
23						Rate Period Average Expense $/kW/year				$ 111.77
24	/1 Source BPA FY 2012 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
25	/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.04% with plant in service 2014 and PNWE fixed fuel. Version 15.0.1									
26	/3 Source NWPCC Microfin Model assumption of $8/kW/yr in 2006$									

Table 3.5

Tier 2 Rate Revenues

	A	D	E
1	Hours	8,760	8,760
2	Notice		Sep 30, 2011
3	Fiscal Year	FY2014	FY2015
4	Rate Period	BP-14	
5	ShortTerm Rate ($/MWh)	$ 35.58	$ 39.65
6	LoadGrowth Rate ($/MWh)	$ 35.58	$ 41.62
7	VR1-2014 Rate ($/MWh)	N/A	$ 41.56
8			
9	ShortTerm		
10	Portfolio Purchased (aMW)	16.000	21.000
11	Portfolio Purchased (MWh)	140,160	183,960
12	Portfolio Obligation /w Losses (aMW)	16.815	28.504
13	Portfolio Obligation /w Losses (MWh)	147,301	249,693
14	Portfolio Billing Determinant (aMW)	16.341	27.700
15	Portfolio Billing Determinant (MWh)	143,147	242,652
16	RECs (MWh)	0	0
17	Base Power Purchase Cost	$ 4,664,525	$ 6,852,510
18	Rate Design Components	$ 190,384	$ 330,968
19	Other Costs	$ -	$ -
20	Rate ($/MWh)	$ 35.58	$ 39.65
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (168,912)	$ (294,570)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (21,472)	$ (36,398)
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	$ 5,093,173	$ 9,621,152
27	Remarketing Credit	$ -	$ -
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ 3,527	$ 121,120
30			
31	LoadGrowth		
32	Portfolio Purchased (aMW)	1.000	5.000
33	Portfolio Purchased (MWh)	8,760	43,800
34	Portfolio Obligation /w Losses (aMW)	1.351	1.722
35	Portfolio Obligation /w Losses (MWh)	11,835	15,085
36	Portfolio Billing Determinant (aMW)	1.313	1.673
37	Portfolio Billing Determinant (MWh)	11,501	14,659
38	RECs (MWh)	0	0
39	Base Power Purchase Cost	$ 291,533	$ 1,713,456
40	Rate Design Components	$ 15,296	$ 19,995
41	Other Costs	$ -	$ -
42	Rate ($/MWh)	$ 35.58	$ 41.62
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,571)	$ (17,796)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
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	$ 409,206	$ 610,121
49	Remarketing Credit	$ -	$ -
50	Remarketing Charge	$ -	$ 53,698
51	Forecast Power Purchase Costs	$ 1,519	$ -

Table 3.5(continued)

Tier 2 Rate Revenues

	A	D	E
1	Hours	8,760	8,760
2	Notice		Sep 30, 2011
3	Fiscal Year	FY2014	FY2015
4	Rate Period	BP-14	
5	ShortTerm Rate ($/MWh)	$ 35.58	$ 39.65
6	LoadGrowth Rate ($/MWh)	$ 35.58	$ 41.62
7	VR1-2014 Rate ($/MWh)	N/A	$ 41.56
8			
9	VR1-2014		
10	Portfolio Purchased (aMW)		47.000
11	Portfolio Purchased (MWh)		411,720
12	Portfolio Obligation /w Losses (aMW)		47.335
13	Portfolio Obligation /w Losses (MWh)		414,655
14	Portfolio Billing Determinant (aMW)		46.000
15	Portfolio Billing Determinant (MWh)		402,961
16	RECs (MWh)		-
17	Base Power Purchase Cost		$ 16,090,105
18	Rate Design Components		$ 549,624
19	Other Costs		$ -
20	Rate ($/MWh)		$ 41.56
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)		$ (489,180)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)		$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)		$ (60,444)
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		$ 16,747,073
27	Remarketing Credit		$ 1,263,781
28	Remarketing Charge		$ -
29	Forecast Power Purchase Costs		$ 5,407
30			
31	Total Tier 2 Rate Revenue Collection	$ 5,502,380	$ 26,978,346
32	Total Tier 2 Remarketing Charge	$ -	$ 53,698
33	Total Tier 2 Remarketing Credit	$ -	$ (1,263,781)
34	Non-Federal Remarketing Credit	$ (334,963)	$ (86,159)
35	Total	$ 5,167,417	$ 25,682,104
36			
37	Total Tier 2 Adjustments and Credits		
38	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (182,483)	$ (801,546)
39	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
40	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (23,197)	$ (99,041)
41	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
42	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -

Table 3.6

Tier 2 Rate Inputs

	A	B	C	D	E	F	G	H
1	Fiscal Year	TSS Rate ($/MWh)	Aurora Flat Annual Block Market Forecast ($/MWh)	Augmentation Price ($/MWh)	Augmentation Amount (MWh)	Section 10 Tier 2 and Non-Federal Resource with DFS Remarketing Value ($/MWh)	Available Section 10 Non-Federal Resource with DFS Remarketing (MWh)	VR1-2014 Remarketing (MWh)
2	FY2014	$ 0.15	$ 28.84	$ 33.47	183,960	$ 33.28	10,065	0
3	FY2015	$ 0.15	$ 28.86	$ 34.08	2,794,440	$ 37.25	2,313	33,927

Table 3.7

Inputs to TSS Monthly Rate and Charge

	A	B	C	D
1	PTK Costs FY2014	PTK Costs FY2015	FY2011 Scheduled (MWh)	FY2012 Scheduled (MWh)
2	$5,044,034	$5,133,306	33,980,349	32,035,871

Table 3.8

Tier 2 Short-Term Rate Costing Table

	A	D	E
1		ST.1.2012 2014	ST.2.2015 2019
2	Hours	8,760	8,760
3	Notice		11/1/2011
4	Fiscal Year	FY2014	FY2015
5	Rate Period	BP-14	
6	Total Forecast Expected Cost	$ 5,092,581	$ 9,620,779
7	Base Power Purchase Cost (Provided by PTL)	$ 4,664,525	$ 6,852,510
8	Power Purchase Cost	$ 4,664,525	$ 6,852,510
9	Transmission	$ -	$ -
10	Third Party PTP	$ -	$ -
11	Ancillary Services	$ -	$ -
12	Scheduling, System Control, Dispatch Services	$ -	$ -
13	Operating Reserves (Spinning and Non-Spinning)	$ -	$ -
14	Within Hour Balancing	$ -	$ -
15	Other BA Losses	$ -	$ -
16	Rate Design Components (Provided by PFR & PTM)	$ 190,384	$ 330,968
17	Resource Support Services	$ 21,472	$ 36,398
18	Diurnal Flattening Service	$ -	$ -
19	DFS Energy (Variable)	$ -	$ -
20	DFS Capacity (Fixed)	$ -	$ -
21	Forced Outage Reserve	$ -	$ -
22	Forced Outage Reserve Capacity (Fixed)		
23	Transmission Scheduling Services	$ 21,472	$ 36,398
24	Transmission Curtailment Management Service Capacity (Fixed)	$ -	$ -
25	Transmission Curtailment Management Service Energy (Variable)	$ -	$ -
26	Alternative Transmission Path Costs	$ -	$ -
27	Generation Imbalance	$ -	$ -
28	TSS - Overhead	$ 21,472	$ 36,398
29	Resource Shaping Charge	$ -	$ -
30	Tier 2 Overhead	$ 168,912	$ 294,570
31	Risk Adder	$ -	$ -
32	Carbon Costs Passthrough	$ -	$ -
33	Renewable Energy Credits (MWh)	0	0
34	Quantity Purchased (MWh)	140,160	183,960
35	Tier 2 Obligation w/o losses (Billing Determinant) (MWh)	143,147	242,652
36	Tier 2 Obligation w losses (MWh)	147,301	249,693
37	Energy (Short)/Long (MWh)	-7,141	-65,733
38	Composite Cost Pool Augmentation (MWh)	0	0
39	Energy Short (MWh)	-7,141	-65,733
40	Energy to be Remarketed (MWh)	0	0
41	Remarketing Available (MWh)	10,065	64,955
42	Total Tier 2 Pool Shortfall (MWh)	-10,216	-68,668
43	Augmentation Price ($/MWh)	$ 33.47	$ 34.08
44	Flat Block RSC ($/MWh)	$ 28.84	$ 28.86
45	Remarketing value ($/MWh)	$ 33.28	$ 37.25
46	Remarketed Purchase (MWh)	7,036	62,179
47	Remarketed Purchase Cost	$ 234,145	$ 2,316,181
48	Remaining Shortfall (MWh)	-105	-3,554
49	Remaining Shortfall Cost	$ 3,527	$ 121,120
50	Tier 2 Balancing Adjustment Debit/(Credit)	$ -	$ -
51	Remarketing Treatment (Remove From Rate)		
52	Additional Remarketing (MWh)		
53	Total Fixed Costs	$ 5,092,581	$ 9,620,779
54	Billing Components		
55	ShortTerm ($/MWh)	$ 35.58	$ 39.65
56	Remarketing Credit	$ -	$ -
57	Remarketing Charge	$ -	$ -
58	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (168,912)	$ (294,570)
59	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
60	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (21,472)	$ (36,398)
61	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -

Table 3.9

Tier 2 Load Growth Rate Costing Table

	A	D	E
1		LG.3.2012_2028	LG.3.2012_2028
2	Hours	8,760	8,760
3	Notice		Sep 30, 2011
4	Fiscal Year	FY2014	FY2015
5	Rate Period	BP-14	
6	Total Forecast Expected Cost	$ 409,166	$ 1,733,451
7	Base Power Purchase Cost (Provided by PTL)	$ 291,533	$ 1,713,456
8	Power Purchase Cost	$ 291,533	$ 1,713,456
9	Transmission	$ -	$ -
10	Third Party PTP	$ -	$ -
11	Ancillary Services	$ -	$ -
12	Scheduling, System Control, Dispatch Services	$ -	$ -
13	Operating Reserves (Spinning and Non-Spinning)	$ -	$ -
14	Within Hour Balancing	$ -	$ -
15	Other BA Losses	$ -	$ -
16	Rate Design Components (Provided by PFR & PTM)	$ 15,296	$ 19,995
17	Resource Support Services	$ 1,725	$ 2,199
18	Diurnal Flattening Service	$ -	$ -
19	DFS Energy (Variable)	$ -	$ -
20	DFS Capacity (Fixed)	$ -	$ -
21	Forced Outage Reserve	$ -	$ -
22	Forced Outage Reserve Capacity (Fixed)		
23	Transmission Scheduling Services	$ 1,725	$ 2,199
24	Transmission Curtailment Management Service Capacity (Fixed)	$ -	$ -
25	Transmission Curtailment Management Service Energy (Variable)	$ -	$ -
26	Alternative Transmission Path Costs	$ -	$ -
27	Generation Imbalance	$ -	$ -
28	TSS - Overhead	$ 1,725	$ 2,199
29	Resource Shaping Charge	$ -	$ -
30	Tier 2 Overhead	$ 13,571	$ 17,796
31	Risk Adder	$ -	$ -
32	Carbon Costs Passthrough	$ -	$ -
33	Renewable Energy Credits (MWh)	0	0
34	Quantity Purchased (MWh)	8,760	43,800
35	Tier 2 Obligation w/o losses (Billing Determinant) (MWh)	11,501	14,659
36	Tier 2 Obligation w losses (MWh)	11,835	15,085
37	Energy (Short)/Long (MWh)	-3,075	28,715
38	Composite Cost Pool Augmentation (MWh)	0	0
39	Energy Short (MWh)	-3,075	0
40	Energy to be Remarketed (MWh)	0	28,715
41	Remarketing Available (MWh)	10,065	64,955
42	Total Tier 2 Pool Shortfall (MWh)	-10,216	-68,668
43	Augmentation Price ($/MWh)	$ 33.47	$ 34.08
44	Flat Block RSC ($/MWh)	$ 28.84	$ 28.86
45	Remarketing value ($/MWh)	$ 33.28	$ 37.25
46	Remarketed Purchase (MWh)	3,029	0
47	Remarketed Purchase Cost	$ 100,818	$ -
48	Remaining Shortfall (MWh)	-45	0
49	Remaining Shortfall Cost	$ 1,519	$ -
50	Tier 2 Balancing Adjustment Debit/(Credit)	$ -	$ -
51	Remarketing Treatment (Remove From Rate)		Yes
52	Additional Remarketing - Vintage Only (MWh)		
53	Total Fixed Costs	$ 409,166	$ 1,733,451
54	Billing Components		
55	LoadGrowth ($/MWh)	$ 35.58	$ 41.62
56	Remarketing Credit	$ -	$ -
57	Remarketing Charge	$ -	$ 53,697.57
58	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,571)	$ (17,796)
59	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
60	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
61	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -

Table 3.10

Tier 2 VR1-2014 Rate Costing Table

	A	E
1		VR1-2014 2016
2	Hours	$ 8,760
3	Notice	
4	Fiscal Year	FY2015
5	Rate Period	BP-14
6	Total Forecast Expected Cost	$ 16,748,540
7	Base Power Purchase Cost (Provided by PTL)	$ 16,090,105
8	Power Purchase Cost	$ 16,090,105
9	Transmission	$ -
10	Third Party PTP	$ -
11	Ancillary Services	$ -
12	Scheduling, System Control, Dispatch Services	$ -
13	Operating Reserves (Spinning and Non-Spinning)	$ -
14	Within Hour Balancing	$ -
15	Other BA Losses	$ -
16	Rate Design Components (Provided by PFR & PTM)	$ 549,624
17	Resource Support Services	$ 60,444
18	Diurnal Flattening Service	$ -
19	DFS Energy (Variable)	$ -
20	DFS Capacity (Fixed)	$ -
21	Forced Outage Reserve	$ -
22	Forced Outage Reserve Capacity (Fixed)	$ -
23	Transmission Scheduling Services	$ 60,444
24	Transmission Curtailment Management Service Capacity (Fixed)	$ -
25	Transmission Curtailment Management Service Energy (Variable)	$ -
26	Alternative Transmission Path Costs	$ -
27	Generation Imbalance	$ -
28	TSS - Overhead	$ 60,444
29	Resource Shaping Charge	$ -
30	Tier 2 Overhead	$ 489,180
31	Risk Adder	$ -
32	Carbon Costs Passthrough	$ -
33	Renewable Energy Credits (MWh)	0
34	Quantity Purchased (MWh)	411,720
35	Tier 2 Obligation w/o losses (Billing Determinant) (MWh)	402,961
36	Tier 2 Obligation w losses (MWh)	414,655
37	Energy (Short)/Long (MWh)	-2,935
38	Composite Cost Pool Augmentation (MWh)	0
39	Energy Short (MWh)	-2,935
40	Energy to be Remarketed (MWh)	0
41	Remarketing Available (MWh)	64,955
42	Total Tier 2 Pool Shortfall (MWh)	-68,668
43	Augmentation Price ($/MWh)	$ 34.08
44	Flat Block RSC ($/MWh)	$ 28.86
45	Remarketing value ($/MWh)	$ 37.25
46	Remarketed Purchase (MWh)	2,776
47	Remarketed Purchase Cost	$ 103,404
48	Remaining Shortfall (MWh)	-159
49	Remaining Shortfall Cost	$ 5,407
50	Tier 2 Balancing Adjustment Debit/(Credit)	
51	Remarketing Treatment (Remove From Rate)	No
52	Additional Remarketing (MWh)	33,927
53	Total Fixed Costs	$ 16,748,540
54	Billing Components	
55	Vintage.1 ($/MWh)	$ 41.56
56	Remarketing Credit	$ 1,263,781
57	Remarketing Charge	$ -
58	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (489,180)
59	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -
60	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (60,444)
61	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -

Table 3.11

Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J
1	1	2	3	4	5	6	7	8	9	10
2	start_date	maturity_date	trade_date	internal_portfolio	tran_status	hours	price	revenue	position	choice
3	10/1/2013	9/30/2014	11/16/2012	ST Default Rate T2	Validated	8,760	$ 33.28	$ (4,664,525)	16.000	Seller's Choice
4	10/1/2013	9/30/2014	11/16/2012	Load Growth T2	Validated	8,760	$ 33.28	$ (291,533)	1.000	Seller's Choice
5	10/1/2014	9/30/2015	12/20/2011	Load Growth T2	Validated	8,760	$ 39.12	$ (1,713,456)	5.000	Seller's Choice
6	10/1/2014	9/30/2015	11/16/2012	ST Default Rate T2	Validated	8,760	$ 37.25	$ (6,852,510)	21.000	Seller's Choice
7	10/1/2014	9/30/2015	11/16/2012	Vintage T2	Validated	8,760	$ 37.25	$ (326,310)	1.000	Seller's Choice
8	10/1/2014	9/30/2015	12/14/2011	Vintage T2	Validated	8,760	$ 39.12	$ (15,763,795)	46.000	Seller's Choice

Table 3.11(continued)

Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I
1	11	12	13	14	15	16	17	18	19
2	product	term	Description	reference	tran_num	buy_sell	RIS	deal_num	pt_of_receipt_loc
3	FLAT	Strip	Energy	Energy	309934	Buy	79571	309934	MID-C
4	FLAT	Strip	Energy	Energy	310005	Buy	79572	309948	MID-C
5	FLAT	Strip	Energy	Energy	245587	Buy	79572	245587	MID-C
6	FLAT	Strip	Energy	Energy	310004	Buy	79571	309931	MID-C
7	FLAT	Strip	Energy	Energy	310003	Buy	79576	309949	MID-C
8	FLAT	Strip	Energy	Energy	245588	Buy	79576	245280	MID-C

Table 3.12

Total Remarketing Charges and Credits

	A	D	E
1		BP-14	
2	Fiscal Year	FY2014	FY2015
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	0	28,715
5	Vintage VR1-2014 Remarket (MWh)	0	33,927
6	Non-Federal Remarket (MWh)	10,065	2,313
7		10,065	64,955
8			
9	ShortTerm Purchase of Remarket (MWh)	7,036	62,179
10	LoadGrowth Purchase of Remarket (MWh)	3,029	0
11	Vintage VR1-2014 Purchase of Remarket (MV	0	2,776
12	BPA Purchase of Remarket (MWh)	0	0
13		10,065	64,955
14			
15	ShortTerm Remarket Credit	$ -	$ -
16	ShortTerm Remarket Charge	$ -	$ -
17	LoadGrowth Remarket Credit	$ -	$ -
18	LoadGrowth Remarket Charge	$ -	$ 53,698
19	Vintage VR1-2014 Remarket Credit	$ -	$ 1,263,781
20	Vintage VR1-2014 Remarket Charge	$ -	$ -
21	Non-Federal Resource Remarketing Credit	$ 334,963	$ 86,159
22			
23	ShortTerm Open Position (MWh)	105	3,554
24	LoadGrowth Open Position (MWh)	45	0
25	Vintage VR1-2014 Open Position (MWh)	0	159
26	BPA Purchase of Remarket (MWh)	0	0
27	Total Open Position (MWh)	151	3,713

Table 3.13

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.3.2012_2028_FY2014	LG.3.2012_2028	FY2014	1.313	1.351
3	LG.3.2012_2028_FY2015	LG.3.2012_2028	FY2015	1.673	1.722
4	ST.1.2012_2014_FY2014	ST.1.2012_2014	FY2014	16.341	16.815
5	ST.2.2015_2019_FY2015	ST.2.2015_2019	FY2015	27.700	28.504
6	V.1.2014_2016_FY2015	V.1.2014_2016	FY2015	46.000	47.335
25	*Notes*				
26	(1) Based on a losses factor of 2.82%				

Table 3.14

Customers Receiving a VR1-2014 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H
1					2014	2015	2014	2015
2	Customers Remarketing Vintage1 Purchases	Remarketing Amount (aMW)	Remarketing Amount (MWh)	Allocation Percentage	Remarket Credit Allocation	Remarket Credit Allocation	Remarket Monthly Credit	Remarket Monthly Credit
3	Burley, City of	1.000	8,760	25.82%	$0	$326,305	$0	$27,192
4	Ellensburg, City of	0.346	3,031	8.93%	$0	$112,902	$0	$9,408
5	Wells Rural Electric Company	1.416	12,404	36.56%	$0	$462,049	$0	$38,504
6	Peninsula Light Company, Inc.	0.612	5,361	15.80%	$0	$199,699	$0	$16,642
7	Columbia Rural Electric Association, Inc.	0.499	4,371	12.88%	$0	$162,826	$0	$13,569
8	Total	3.873	33,927	100.00%		$1,263,781		

Table 3.15

Customers Receiving a Load Growth Billing Adjustment

	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	15,085	28,715			
5		Price	39.12	39.12	39.12			
6		Cost	1,713,456	590,114	1,123,342			
7								
8		Remarket Price			37.25			
9		Remarket Credit			1,069,644			
10		Stranded Cost			53,698			
11						Initial		Total
12				AHWML	Allocation	Stranded Cost	Cost Cap	Stranded Cost
13		Load Growth Pool Members		<1 aMW	Percentage	Allocation	Reallocation	Allocation
14	10055	Albion, City of		0.010	0.085%	45	2	47
15	10005	Alder Mutual		0.043	0.363%	195	8	203
16	10015	Asotin PUD #1		0.007	0.059%	32	1	33
17	10059	Bandon, City of		0.259	2.189%	1,175	45	1,221
18	10025	Benton REA		0	0.000%	0	0	0
19	10061	Blaine, City of		0.425	3.592%	1,929	74	2,003
20	10065	Cascade Locks, City of		0	0.000%	0	0	0
21	10068	Chewelah, City of		0	0.000%	0	0	0
22	10109	Columbia Basin Elec		0.688	5.814%	3,122	120	3,243
23	10111	Columbia Power Coop		0.046	0.389%	209	8	217
24	10116	Consolidated Irrig Dist		0.532	4.496%	2,414	-1,978	436
25	10378	Coulee Dam, City of		0.154	1.301%	699	27	726
26	10070	Declo, City of		0.011	0.093%	50	2	52
27	10071	Drain, City of		0	0.000%	0	0	0
28	10142	East End Mutual Electric		0.105	0.887%	476	18	495
29	10144	Eatonville, City of		0.234	1.978%	1,062	41	1,103
30	10156	Elmhurst Mutual P & L		0.712	6.017%	3,231	125	3,356
31	10174	Farmers Elec Coop		0.012	0.101%	54	2	57
32	10177	Ferry County PUD #1		0.449	3.794%	2,038	79	2,116
33	10190	Grant County PUD #2		0.488	4.124%	2,215	85	2,300
34	10197	Harney Elec Coop		0	0.000%	0	0	0
35	10597	Hermiston, City of		0	0.000%	0	0	0
36	10202	Hood River Elec Coop		0.438	3.702%	1,988	77	2,064
37	10230	Kittitas County PUD #1		0.574	4.851%	2,605	100	2,705
38	10235	Lakeview L & P (WA)		0	0.000%	0	0	0
39	10242	Lost River Elec Coop		0	0.000%	0	0	0
40	10246	Mason County PUD #1		0.494	4.175%	2,242	86	2,328
41	10256	Midstate Elec Coop		0.497	4.200%	2,255	87	2,342
42	10080	Milton, Town of		0.065	0.549%	295	11	306
43	10082	Minidoka, City of		0.015	0.127%	68	3	71
44	10260	Modern Elec Coop		0.561	4.741%	2,546	98	2,644
45	10083	Monmouth, City of		0.340	2.873%	1,543	60	1,602
46	10273	Nespelem Valley Elec		0.688	5.814%	3,122	120	3,243
47	10284	Ohop Mutual Light		0.782	6.609%	3,549	137	3,686
48	10288	Orcas P & L		0	0.000%	0	0	0
49	10291	Oregon Trail Coop		0	0.000%	0	0	0
50	10304	Parkland L & W		0.518	4.378%	2,351	91	2,441
51	10086	Plummer, City of		0.271	2.290%	1,230	47	1,277
52	10338	Riverside Elec Coop		0	0.000%	0	0	0
53	10342	Salem Elec Coop		0.467	3.947%	2,119	82	2,201
54	10352	Skamania PUD #1		0	0.000%	0	0	0
55	10360	Southside Elec Lines		0	0.000%	0	0	0
56	10379	Steilacoom, Town of		0.134	1.132%	608	23	632
57	10095	Sumas, Town of		0.167	1.411%	758	29	787
58	10097	Troy, City of		0.177	1.496%	803	31	834
59	10172	U.S. Air Force, Fairchild		0	0.000%	0	0	0
60	10406	U.S. DOE Albany		0.061	0.516%	277	11	287
61	10326	U.S. Navy, Bremerton		0	0.000%	0	0	0
62	10409	U.S. Navy, Bangor		0	0.000%	0	0	0
63	10408	U.S. Navy, Everett		0	0.000%	0	0	0
64	10482	Umpqua Indian Utility		0.044	0.372%	200	8	207
65	10440	Wahkiakum PUD #1		0.470	3.972%	2,133	82	2,215
66	10442	Wasco Elec Coop		0.518	4.378%	2,351	91	2,441
67	11680	Weiser, City of		0.377	3.186%	1,711	66	1,777
68		Total		11.833	100.000%	53,698	0	53,698

Table 3.16

Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	F	G	H	I	J
1			Monthly Irrigation Rate Mitigation Amounts for Exhibit D of the Region Dialogue Contracts (in MWh)							
2	BESID	Customer	May	June	July	August	September	TOTAL	LDD	Total IRD Amount * 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%	1514.291
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%	5388.556
8	10027	Big Bend	32,097.789	47,948.108	50,352.318	47,379.798	31,891.527	209,669.540	7.00%	14676.868
9	10391	United	5,273.820	10,806.706	12,770.236	9,182.704	6,236.687	44,270.153	3.50%	1549.455
10	10046	Central Elec	4,687.388	8,675.756	9,539.100	10,094.599	8,088.614	41,085.457	7.00%	2875.982
11	10109	Columbia Basin	4,185.302	5,469.756	4,513.543	3,665.441	3,266.293	21,100.335	7.00%	1477.023
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%	9425.917
14	10173	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3101.700
15	10197	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6992.944
16	10209	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4207.889
17	10242	Lost River	3,725.641	9,902.214	10,705.288	8,479.424	4,746.327	37,558.894	6.50%	2441.328
18	10256	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	7.00%	2904.252
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	6.00%	2175.636
21	10331	Raft River	23,443.131	30,794.718	32,636.209	27,344.114	18,868.686	133,086.858	7.00%	9316.080
22	10142	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	3.00%	173.085
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.00%	124.656
24	10360	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	4.00%	800.374
25	10343	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	5.00%	525.283
26	10369	Surprise Valley	6,464.252	9,066.424	11,421.596	11,671.642	7,586.987	46,210.901	7.00%	3234.763
27	10388	Umatilla	39,288.078	52,679.345	55,478.176	49,073.469	32,253.359	228,772.427	6.00%	13726.346
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	5.50%	394.424
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%	2720.428
32	10258	Mission Valley	1,857.275	3,714.550	6,500.462	5,571.825	742.910	18,387.022	6.50%	1195.156
33								Wt. LDD	4.90%	

Table 3.17
Rates and Charges for RSS and Related Services in FY 2014 and FY 2015

	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 FY2014 Annual aMW	Exh. A FY2015 Annual aMW
2	Benton Rural Electric Association	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	1.402	2.547
3	Big Bend Electric Cooperative	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	1.652	0.000
4	Tier 1	Klondike 3	DFS TSS TCMS RSC	FY2014&FY2015	14.748	15.967	15.945
5	City of Bonners Ferry	Moyie	GMS	FY2014&FY2015	N/A	1.881	1.881
6	City of Centralia	Yelm Hydro	GMS	FY2014&FY2015	N/A	7.114	7.114
7	City of Centralia	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.675	1.000
8	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.967	1.000
9	City of Forest Grove	Priest Rapids	SCS	FY2014&FY2015	N/A	1.454	1.455
10	City of Forest Grove	Wanapum	SCS	FY2014&FY2015	N/A	1.481	1.481
11	The City of McMinnville, a municipal corporatio	Priest Rapids	SCS	FY2014&FY2015	N/A	1.454	1.455
12	The City of McMinnville, a municipal corporatio	Wanapum	SCS	FY2014&FY2015	N/A	1.481	1.481
13	City of Milton-Freewater	Priest Rapids	SCS	FY2014&FY2015	N/A	1.454	1.455
14	City of Milton-Freewater	Wanapum	SCS	FY2014&FY2015	N/A	1.481	1.481
15	City of Richland, Washington	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	4.304	0.000
16	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2014&FY2015	1.329	0.673	0.673
17	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2014&FY2015	1.535	1.231	1.231
18	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2014&FY2015	1.079	1.077	1.077
19	Idaho County Light & Power Cooperative Assoc	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	0.531	0.000
20	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2014&FY2015	N/A	0.484	0.485
21	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2014&FY2015	N/A	0.494	0.494
22	Lower Valley Energy, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	2.461	0.000
23	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2014&FY2015	N/A	0.656	0.656
24	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2014&FY2015	0.883	0.809	0.809
25	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2015	1.002	0.000	0.920
26	Mission Valley Power	Kerr	TSS TCMS	FY2014&FY2015	N/A	9.657	9.657
27	PNGC	Lake Creek	SCS	FY2014&FY2015	N/A	1.530	1.530
28	PNGC	Chester Hydro	DFS FOR RSC	FY2014&FY2015	0.446	0.967	0.967
29	PNGC	Island Park	SCS	FY2014&FY2015	N/A	0.992	0.992
30	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	25.000	25.000
31	Northern Wasco County People's Utility District	McNary Fishway	GMS	FY2014&FY2015	N/A	4.404	4.404
32	Peninsula Light Company	Harvest Wind	DFS TSS TCMS RSC	FY2015	1.021	0.000	1.000
33	Peninsula Light Company	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	0.454	0.000
34	United Electric Co-op, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	1.547	0.000
35	Vera Water & Power	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	0.054	0.000
36	Wells Rural Electric Company	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	0.229	0.000
37	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	2.363	2.363
38	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	2.968	0.000
39	Columbia REA	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	2.118	0.000
40	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2014&FY2015	2.515	2.514	2.514
41	Inland	Unspecified Resource Amounts	TSS TCMS	FY2014	N/A	1.985	0.000
42	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2015	N/A	0.000	10.000

Table 3.17(continued)
Rates and Charges for RSS and Related Services in FY 2014 and FY 2015

	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 FY 2014	Revenue Credit to Non-Slice Cost Pool FY2014	Revenue Credit to Composite Cost Pool FY 2015	Revenue Credit to Non-Slice Cost Pool FY2015	Total $/MWh Equivalent Rate
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$216	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,594	$ -	$ 2,594	$ -	$ 0.15
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$181	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,170	$ -	$ -	$ -	$ 0.15
4	$ 2.83	$ 132,811	$ 12.30	$ 45,081	$ 4.18	$ -	$ -	$990	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,971,860	$ 540,969	$ 1,971,860	$ 540,969	$ 19.40
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 771	$ 0.56	$ 9,258	$ -	$ 9,258	$ -	$ 0.56
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,282	$ 0.63	$ 39,382	$ -	$ 39,382	$ -	$ 0.63
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,100	$ -	$ 1,100	$ -	$ 0.15
8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$108	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,292	$ -	$ 1,292	$ -	$ 0.15
9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$645	$ 0.61	$ -	$ -	$ 7,740	$ -	$ 7,740	$ -	$ 0.61
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$652	$ 0.60	$ -	$ -	$ 7,824	$ -	$ 7,824	$ -	$ 0.60
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$645	$ 0.61	$ -	$ -	$ 7,740	$ -	$ 7,740	$ -	$ 0.61
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$652	$ 0.60	$ -	$ -	$ 7,824	$ -	$ 7,824	$ -	$ 0.60
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$645	$ 0.61	$ -	$ -	$ 7,740	$ -	$ 7,740	$ -	$ 0.61
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$652	$ 0.60	$ -	$ -	$ 7,824	$ -	$ 7,824	$ -	$ 0.60
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$471	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,655	$ -	$ -	$ -	$ 0.15
16	$ 1.03	$ 6,783	$ 6.97	$(13,599)	$(13.97)	$ 249.00	$ 0.26	$ 74	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,244	$ (163,183)	$ 97,244	$ (163,183)	$ (5.63)
17	$ 0.32	$ 5,716	$ 5.09	$ (6,414)	$ (5.71)	$ 423.00	$ 0.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 77,964	$ (76,965)	$ 77,964	$ (76,965)	$ 0.08
18	$ 0.11	$ 1,215	$ 1.54	$ (488)	$ (0.62)	$ 613.00	$ 0.78	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,952	$ (5,851)	$ 22,952	$ (5,851)	$ 1.81
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 698	$ -	$ -	$ -	$ 0.15
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$215	$ 0.61	$ -	$ -	$ 2,577	$ -	$ 2,577	$ -	$ 0.61
21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$217	$ 0.60	$ -	$ -	$ 2,608	$ -	$ 2,608	$ -	$ 0.60
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$269	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,234	$ -	$ -	$ -	$ 0.15
23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 72	$ 0.15	$ -	$ -	$292	$ 0.61	$ -	$ -	$ 4,369	$ -	$ 4,369	$ -	$ 0.76
24	$ 3.27	$ 7,780	$ 12.04	$ (1,304)	$ (2.02)	$ -	$ -	$ 89	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 119,785	$ (15,649)	$ 119,785	$ (15,649)	$ 13.43
25	$ 3.20	$ 9,011	$ 12.28	$ (1,318)	$ (1.80)	$ -	$ -	$101	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 137,547	$ (15,817)	$ 13.82
26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$990	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,880	$ -	$ 11,880	$ -	$ 0.14
27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$619	$ 0.55	$ -	$ -	$ 7,424	$ -	$ 7,424	$ -	$ 0.55
28	$ 0.53	$ 2,613	$ 8.00	$ 8,583	$ 26.28	$ 70.00	$ 0.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,282	$ 102,996	$ 34,282	$ 102,996	$ 35.02
29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$400	$ 0.55	$ -	$ -	$ 4,795	$ -	$ 4,795	$ -	$ 0.55
30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$990	$ 0.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,880	$ -	$ 11,880	$ -	$ 0.05
31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,036	$ 0.63	$ 24,433	$ -	$ 24,433	$ -	$ 0.63
32	$ 3.26	$ 9,513	$ 12.73	$ (75)	$ (0.10)	$ -	$ -	$109	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 144,712	$ (897)	$ 16.04
33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 597	$ -	$ -	$ -	$ 0.15
34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$169	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,033	$ -	$ -	$ -	$ 0.15
35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 71	$ -	$ -	$ -	$ 0.15
36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 301	$ -	$ -	$ -	$ 0.15
37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$259	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,105	$ -	$ 3,105	$ -	$ 0.15
38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$325	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,900	$ -	$ -	$ -	$ 0.15
39	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$232	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,783	$ -	$ -	$ -	$ 0.15
40	$ 0.15	$ 10,130	$ 5.50	$ (2,086)	$ (1.13)	$1,066.00	$ 0.58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 137,769	$ (25,028)	$ 137,769	$ (25,028)	$ 5.10
41	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$217	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,608	$ -	$ -	$ -	$ 0.15
42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$990	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,880	$ -	$ 0.14

Table 3.18

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

	A	B	C	D	E	F
1		2014	2014	2014	2014	2014
2	Customers Remarketing 2014 Non-Federal Resource Purchases	Remarketing Amount (aMW)	Remarketing Amount (MWh)	Allocation Percentage	Remarket Credit Allocation	Remarket Monthly Credit
3	Flathead Electric Cooperative, Inc.	1.077	9,435	93.73%	$313,973	$26,164
4	Public Utility District No. 3 of Mason County, Washington: Nine Canyon Resource	0.072	631	6.27%	$20,990	$1,749
5	Total	1.149	10,065	100.00%	$334,963	
6						
7						
8		2015	2015	2015	2015	2015
9	Customers Remarketing 2015 Non-Federal Resource Purchases	Amount (aMW)	Amount (MWh)	Allocation Percentage	Remarket Credit Allocation	Remarket Monthly Credit
10	Public Utility District No. 3 of Mason County, Washington: White Creek Resource	0.264	2,313	100.00%	$86,159	$7,180
11	Total	0.264	2,313	100.00%	$86,159	

Table 3.19

Transmission Scheduling Service OATI Registration Fee Customer List

	A	B	C
1	Customer	FY2014 Charge	FY2015 Charge
2	Benton Rural Electric Association	$150	$150
3	Big Bend Electric Cooperative	$150	$0
4	Centralia, City of	$150	$150
5	City of Cheney	$150	$150
6	Idaho County Light & Power Cooperative Association, Inc.	$150	$0
7	Inland Power and Light Company	$150	$0
8	Lower Valley Energy,Inc	$150	$0
9	Mission Valley Power	$150	$150
10	Peninsula Light Company	$150	$150
11	Public Utility District No. 1 of Clallam County	$150	$150
12	Public Utility District No. 3 of Mason County	$150	$150
13	Richland, City of	$150	$150
14	United Electric Co-op, Inc.	$150	$0
15	Vera Water & Power	$150	$0
16	Wells Rural Electric Company	$150	$0

Table 3.20

Customers Receiving Resource Remarketing Service Credits

	A	B	C	D	E	F	G
1	Customer	Resource	Remarketed Amount (aMW)	Remarketed Amount (MWh)	Remarketing Price ($/MWh)	Annual Remarketing Credit	Monthly Remarketing Credit
2	Flathead Electric Co-op	Stoltze	2.514	22,023	28.84	$635,133	$52,928

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SECTION 4: REVENUE FORECAST

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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 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.4 Load Shaping and Demand Revenue – FY 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.5 Irrigation Rate Discount (IRD) – FY 2014-2015
Table shows calculation of IRD credit at proposed rates.

Table 4.6 Low Density Discount (LDD) – FY 2014-2015
Table shows calculation of LDD credit at proposed rates.

Table 4.7 Tier 2 Revenue – FY 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.8 Direct Service Industries (DSI) Revenues – FY 2014-2015
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														2013	
2	**Category**	**201210**	**201211**	**201212**	**201301**	**201302**	**201303**	**201304**	**201305**	**201306**	**201307**	**201308**	**201309**	**$ (000's)**	**aMW**
3	Composite Revenue	189,911	189,911	189,911	189,911	189,911	189,667	189,667	189,667	189,667	189,667	189,667	189,667	2,277,224	5,052
4	Non-Slice Revenue	(27,379)	(27,379)	(27,379)	(27,379)	(27,379)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(328,205)	-
5	Slice	-	-	-	-	-	-	-	-	-	-	-	-	-	2,072
6	Load Shaping Revenue	772	(11,495)	10,848	21,522	18,965	17,174	26,368	(43,567)	(25,966)	(24,451)	(1,671)	(7,877)	(19,379)	(29)
7	Demand Revenue	1,697	1,201	2,558	3,656	786	5,033	5,226	3,677	3,425	5,521	6,044	3,663	42,486	-
8	Irrigation Rate Discount	-	-	-	-	-	-	-	(2,976)	(4,447)	(5,122)	(4,203)	(2,557)	(19,305)	-
9	Low Density Discount	(2,406)	(1,968)	(2,508)	(2,857)	(2,630)	(3,047)	(1,896)	(2,445)	(2,616)	(3,001)	(2,521)	(4,181)	(32,077)	-
10	Tier 2	2,049	1,986	2,049	2,049	1,851	2,010	2,010	2,010	2,010	2,010	2,010	2,010	24,055	56
11	RSS (Non-Federal)	156	93	57	93	82	20	21	21	21	20	20	94	698	-
12	**PF customers (TRM) sub-total**	**164,800**	**152,349**	**175,535**	**186,995**	**181,586**	**183,527**	**194,066**	**119,057**	**134,764**	**137,314**	**162,016**	**153,489**	**1,945,498**	**7,151**
13	**DSIs sub-total**	**8,512**	**8,290**	**9,090**	**8,811**	**8,231**	**8,823**	**8,107**	**7,394**	**7,122**	**8,908**	**9,510**	**8,873**	**101,673**	**320**
14	**FPS sub-total**	**226**	**195**	**249**	**298**	**215**	**228**	**228**	**228**	**228**	**228**	**228**	**228**	**2,781**	**8**
15	**Short-term market sales sub-total**	**17,350**	**32,121**	**51,357**	**42,264**	**27,087**	**34,701**	**64,742**	**48,155**	**46,897**	**38,889**	**17,206**	**10,063**	**430,832**	**1,874**
16	**Long Term Contractual Obligations sub-total**	**29**	**6,633**	**6,848**	**6,838**	**6,266**	**3,425**	**3,336**	**79**	**85**	**82**	**62**	**39**	**33,722**	**62**
17	**Canadian Entitlement Return**	-	-	-	-	-	-	-	-	-	-	-	-	-	**505**
18	**Renewable Energy Certificates sub-total**	-	**27**	**2**	-	-	**1,070**	**33**	-	-	-	-	-	**1,132**	-
19	Miscellaneous Credits	31	31	(48)	33	30	119	119	119	119	119	119	119	910	-
20	Load Shaping True up	-	-	-	-	-	-	-	-	-	-	-	1,898	1,898	-
21	Slice True up	-	-	-	-	-	-	-	-	-	-	-	(7,795)	(7,795)	-
22	**Other Sales sub-total**	**31**	**31**	**(48)**	**33**	**30**	**119**	**119**	**119**	**119**	**119**	**119**	**(5,777)**	**(4,986)**	-
23	**Gross Sales**	**$190,948**	**$199,646**	**$243,033**	**$245,239**	**$223,416**	**$231,894**	**$270,630**	**$175,033**	**$189,215**	**$185,541**	**$189,141**	**$166,915**	**$2,510,651**	**9,920**
24	GTA Delivery charge	160	208	219	249	193	165	165	165	165	165	165	165	2,184	-
25	Energy Efficiency Revenues	146	329	468	138	168	703	1,287	1,287	1,287	1,287	1,287	1,287	9,675	-
26	Irrigation Pumping Power	79	1	1	1	1	9	84	181	216	275	256	181	1,284	174
27	Reserve Energy	804	804	804	804	804	804	804	804	804	804	804	804	9,645	3
28	Downstream Benefits	471	471	471	471	471	508	508	508	508	508	508	508	5,909	-
29	Upper Baker Revenues	-	96	101	99	101	-	-	-	-	-	-	-	397	1
30	**Miscellaneous Revenues**	**$1,660**	**$1,908**	**$2,064**	**$1,761**	**$1,738**	**$2,189**	**$2,847**	**$2,945**	**$2,979**	**$3,039**	**$3,020**	**$2,944**	**$29,094**	**178**
31	Regulating Reserve	550	550	550	550	550	550	550	550	550	550	550	550	6,601	-
32	Variable Energy Resource Balancing Service Reserve - Wind	4,489	4,489	4,679	4,679	4,711	4,707	4,468	4,468	4,591	4,591	4,703	4,703	55,277	-
33	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustment	-	-	-	-	-	244	324	324	283	304	340	340	2,158	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	-	-	-	-	-	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(1,680)	-
35	VERBS Supplemental Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	VERBS for Solar	-	-	-	-	-	1	1	1	1	1	1	1	9	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	381	381	381	381	381	381	381	381	381	381	381	381	4,576	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	98	98	98	98	98	98	98	98	98	98	98	98	1,177	-
39	Operating Reserve - Spinning	2,076	2,196	2,621	2,745	2,433	2,416	2,367	2,293	2,469	2,457	2,203	2,007	28,284	-
40	Operating Reserve - Supplemental	1,764	1,866	2,228	2,333	2,068	2,053	2,011	1,949	2,098	2,088	1,872	1,705	24,036	-
41	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	(41)	-	-	-	-	-	-	(41)	-
42	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	(35)	-	-	-	-	-	-	(35)	-
43	Synchronous Condensing	157	157	157	157	157	157	157	157	157	157	157	157	1,880	-
44	Generation Dropping	31	31	31	31	31	31	31	31	31	31	31	31	377	-
45	Energy Imbalance	638	629	438	416	295	118	221	79	170	208	(4)	(46)	3,161	-
46	Generation Imbalance	-	-	-	-	-	869	1,061	737	751	1,011	417	566	5,411	-
47	Persistent Deviation - Energy Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Persistent Deviation - Generation Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Station Service	246	246	246	246	246	246	246	246	246	246	246	246	2,950	9
50	Redispatch	48	1	2	-	0	33	33	33	33	33	33	33	285	-
51	COE/Reclamation Network/Delivery Facilities Segmentation	592	592	592	592	592	592	592	592	592	592	592	592	7,105	-
52	Operating Reserve - Energy	55	114	60	82	58	74	53	45	48	128	99	86	901	-
53	**Generation Inputs / Inter-business line**	**11,126**	**11,350**	**12,084**	**12,310**	**11,621**	**12,254**	**12,355**	**11,745**	**12,261**	**12,636**	**11,479**	**11,210**	**142,432**	**9**
54	4(h)(10)(c)	5,796	15,223	4,387	4,466	6,175	10,575	8,040	5,831	5,796	5,796	5,538	9,026	86,649	-
55	Colville and Spokane Settlements	383	383	383	383	383	383	383	383	383	383	383	383	4,600	-
56	**Treasury Credits**	**6,179**	**15,606**	**4,770**	**4,850**	**6,559**	**10,958**	**8,423**	**6,214**	**6,179**	**6,179**	**5,922**	**9,409**	**91,249**	-
57	Augmentation Power Purchase total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Balancing Power Purchase sub-total	15,074	11,617	11,842	11,230	19,600	28,079	8,405	397	75	895	6,156	6,293	119,664	199
59	Other Power Purchase total	1,007	8,086	9,111	11,637	9,980	9,967	9,340	1,952	1,952	1,952	1,952	1,952	68,885	139
60	**Power Purchases**	**16,081**	**19,703**	**20,953**	**22,868**	**29,580**	**38,046**	**17,745**	**2,349**	**2,026**	**2,846**	**8,108**	**8,245**	**188,549**	**338**

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														2014	
2	**Category**	**201310**	**201311**	**201312**	**201401**	**201402**	**201403**	**201404**	**201405**	**201406**	**201407**	**201408**	**201409**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 190,577	$ 2,286,922	6,982
4	Non-Slice Revenue	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (27,517)	$ (330,200)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (778)	$ (7,187)	$ 14,886	$ 15,637	$ 21,144	$ 14,174	$ 29,201	$ (49,912)	$ (28,436)	$ (24,495)	$ (7,157)	$ (181)	$ (23,106)	(54)
7	Demand Revenue	$ 4,896	$ 3,248	$ 6,573	$ 7,123	$ 4,013	$ 5,467	$ 5,273	$ 4,246	$ 3,201	$ 5,063	$ 4,839	$ 4,382	$ 58,325	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,925)	$ (4,318)	$ (4,985)	$ (4,090)	$ (2,494)	$ (18,812)	-
9	Low Density Discount	$ (1,772)	$ (1,565)	$ (1,993)	$ (1,942)	$ (1,975)	$ (1,878)	$ (2,214)	$ (1,261)	$ (1,647)	$ (1,849)	$ (2,044)	$ (1,909)	$ (22,047)	-
10	Tier 2	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 7,097	18
11	RSS (Non-Federal)	$ 20	$ 21	$ 19	$ 20	$ 19	$ 20	$ 21	$ 21	$ 21	$ 20	$ 20	$ 20	$ 243	-
12	**PF customers (TRM) sub-total**	**$ 166,018**	**$ 158,169**	**$ 183,138**	**$ 184,489**	**$ 186,853**	**$ 181,435**	**$ 195,933**	**$ 113,821**	**$ 132,472**	**$ 137,405**	**$ 155,220**	**$ 163,469**	**$ 1,958,422**	**6,945**
13	**DSIs sub-total**	**$ 8,269**	**$ 8,094**	**$ 8,854**	**$ 8,570**	**$ 8,026**	**$ 8,604**	**$ 7,895**	**$ 7,164**	**$ 6,933**	**$ 8,644**	**$ 9,227**	**$ 8,912**	**$ 99,190**	**312**
14	**FPS sub-total**	**$ 244**	**$ 249**	**$ 269**	**$ 279**	**$ 254**	**$ 254**	**$ 239**	**$ 249**	**$ 254**	**$ 264**	**$ 259**	**$ 244**	**$ 3,052**	**8**
15	**Short-term market sales sub-total**	**$ 3,055**	**$ 5,804**	**$ 5,403**	**$ 25,917**	**$ 22,803**	**$ 38,044**	**$ 47,012**	**$ 52,848**	**$ 54,697**	**$ 42,597**	**$ 17,483**	**$ 6,489**	**$ 322,152**	**1,661**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**59**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**500**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**-**
19	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
20	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
23	**Gross Sales**	**$177,626**	**$178,209**	**$203,716**	**$225,296**	**$223,467**	**$232,424**	**$254,009**	**$174,161**	**$194,441**	**$188,992**	**$182,250**	**$179,152**	**$2,413,742**	**9,485**
24	GTA Delivery charge	$ 155	$ 175	$ 190	$ 195	$ 180	$ 170	$ 160	$ 155	$ 155	$ 165	$ 170	$ 145	$ 2,015	-
25	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
26	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,393	174
27	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
28	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
29	Upper Baker Revenues	$ -	$ 101	$ 108	$ 105	$ 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 422	1
30	**Miscellaneous Revenues**	**$2,210**	**$2,227**	**$2,233**	**$2,231**	**$2,235**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$32,597**	**178**
31	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
32	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 53,153	-
33	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (125)	-
35	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	VERBS for Solar	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 6	$ 42	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
39	Operating Reserve - Spinning	$ 1,630	$ 1,733	$ 1,927	$ 1,988	$ 1,926	$ 1,852	$ 1,855	$ 1,960	$ 2,093	$ 1,934	$ 1,746	$ 1,549	$ 22,193	-
40	Operating Reserve - Supplemental	$ 1,385	$ 1,473	$ 1,638	$ 1,690	$ 1,637	$ 1,574	$ 1,576	$ 1,666	$ 1,778	$ 1,644	$ 1,484	$ 1,316	$ 18,860	-
41	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
44	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persistent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Persistent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
49	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,949	9
50	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
51	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
52	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	**Generation Inputs / Inter-business line**	**$ 9,526**	**$ 9,717**	**$ 10,076**	**$ 10,189**	**$ 10,074**	**$ 9,937**	**$ 9,942**	**$ 10,136**	**$ 10,382**	**$ 10,089**	**$ 9,740**	**$ 9,378**	**$ 119,186**	**9**
54	4(h)(10)(c)	$ 10,011	$ 7,821	$ 10,029	$ 12,393	$ 10,429	$ 8,578	$ 6,319	$ 5,947	$ 6,224	$ 5,648	$ 5,791	$ 7,983	$ 97,173	-
55	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
56	**Treasury Credits**	**$ 10,394**	**$ 8,205**	**$ 10,413**	**$ 12,777**	**$ 10,812**	**$ 8,962**	**$ 6,702**	**$ 6,330**	**$ 6,608**	**$ 6,031**	**$ 6,174**	**$ 8,366**	**$ 101,773**	**-**
57	Augmentation Power Purchase total	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 516	$ 6,198	21
58	Balancing Power Purchase sub-total	$ 4,611	$ 4,846	$ 7,633	$ 2,843	$ 2,612	$ 608	$ 56	$ 33	$ 33	$ 240	$ 697	$ 3,208	$ 27,421	156
59	Other Power Purchase total	$ 449	$ 5,999	$ 6,287	$ 6,476	$ 5,972	$ 6,475	$ 6,462	$ 449	$ 436	$ 449	$ 449	$ 436	$ 40,340	87
60	**Power Purchases**	**$ 5,577**	**$ 11,361**	**$ 14,436**	**$ 9,836**	**$ 9,100**	**$ 7,600**	**$ 7,035**	**$ 999**	**$ 985**	**$ 1,206**	**$ 1,663**	**$ 4,160**	**$ 73,958**	**264**

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														**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 191,338	$ 2,296,054	7,011
4	Non-Slice Revenue	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (27,668)	$ (332,018)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 700	$ (5,440)	$ 18,004	$ 18,764	$ 24,020	$ 16,380	$ 30,945	$ (49,294)	$ (27,268)	$ (22,980)	$ (5,660)	$ 1,389	$ (439)	19
7	Demand Revenue	$ 4,838	$ 2,319	$ 7,550	$ 7,416	$ 4,237	$ 5,633	$ 5,446	$ 3,313	$ 4,187	$ 5,283	$ 4,964	$ 4,572	$ 59,756	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,925)	$ (4,318)	$ (4,985)	$ (4,090)	$ (2,494)	$ (18,812)	-
9	Low Density Discount	$ (1,804)	$ (1,575)	$ (2,061)	$ (1,981)	$ (2,017)	$ (1,914)	$ (2,255)	$ (1,267)	$ (1,701)	$ (1,887)	$ (2,084)	$ (1,946)	$ (22,492)	-
10	Tier 2	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 33,304	75
11	RSS (Non-Federal)	$ 20	$ 21	$ 19	$ 20	$ 19	$ 20	$ 21	$ 21	$ 21	$ 20	$ 20	$ 20	$ 243	-
12	**PF customers (TRM) sub-total**	**$ 170,199**	**$ 161,770**	**$ 189,957**	**$ 190,663**	**$ 192,704**	**$ 186,564**	**$ 200,602**	**$ 116,294**	**$ 137,367**	**$ 141,896**	**$ 159,595**	**$ 167,985**	**$ 2,015,596**	**7,105**
13	**DSIs sub-total**	**$ 8,269**	**$ 8,094**	**$ 8,854**	**$ 8,570**	**$ 8,026**	**$ 8,604**	**$ 7,895**	**$ 7,164**	**$ 6,933**	**$ 8,644**	**$ 9,227**	**$ 8,912**	**$ 99,190**	**312**
14	**FPS sub-total**	**$ 249**	**$ 254**	**$ 274**	**$ 284**	**$ 259**	**$ 259**	**$ 244**	**$ 254**	**$ 259**	**$ 269**	**$ 264**	**$ 249**	**$ 3,119**	**9**
15	**Short-term market sales sub-total**	**$ 6,239**	**$ 5,736**	**$ 12,098**	**$ 28,197**	**$ 28,179**	**$ 40,559**	**$ 44,067**	**$ 46,400**	**$ 50,961**	**$ 47,174**	**$ 24,796**	**$ 5,911**	**$ 340,317**	**1,654**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**74**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**475**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	-
19	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
20	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	-
23	**Gross Sales**	**$184,996**	**$181,747**	**$217,235**	**$233,756**	**$234,700**	**$240,119**	**$255,739**	**$170,192**	**$195,605**	**$198,065**	**$193,944**	**$183,097**	**$2,489,194**	**9,629**
24	GTA Delivery charge	$ 160	$ 180	$ 190	$ 195	$ 180	$ 175	$ 160	$ 155	$ 155	$ 165	$ 170	$ 145	$ 2,030	-
25	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
26	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,394	174
27	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
28	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
29	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
30	**Miscellaneous Revenues**	**$2,210**	**$2,236**	**$2,241**	**$2,236**	**$2,238**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$32,621**	**178**
31	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
32	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,429	$ 4,755	$ 4,755	$ 4,755	$ 4,755	$ 4,755	$ 4,755	$ 55,107	-
33	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (10)	$ (125)	-
35	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	VERBS for Solar	$ 6	$ 6	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 77	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
39	Operating Reserve - Spinning	$ 1,593	$ 1,713	$ 1,939	$ 2,043	$ 1,979	$ 1,903	$ 1,905	$ 2,010	$ 2,146	$ 1,986	$ 1,793	$ 1,592	$ 22,602	-
40	Operating Reserve - Supplemental	$ 1,354	$ 1,455	$ 1,648	$ 1,736	$ 1,682	$ 1,617	$ 1,619	$ 1,708	$ 1,824	$ 1,688	$ 1,524	$ 1,353	$ 19,208	-
41	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
44	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persistent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Persistent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
49	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,949	9
50	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
51	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
52	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	**Generation Inputs / Inter-business line**	**$ 5,031**	**$ 5,252**	**$ 5,672**	**$ 5,864**	**$ 5,745**	**$ 5,605**	**$ 5,609**	**$ 5,803**	**$ 6,055**	**$ 5,759**	**$ 5,402**	**$ 5,030**	**$ 121,934**	**9**
54	4(h)(10)(c)	$ 10,071	$ 7,630	$ 8,595	$ 11,218	$ 9,271	$ 7,593	$ 6,065	$ 5,755	$ 6,523	$ 5,534	$ 5,496	$ 9,244	$ 92,996	-
55	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
56	**Treasury Credits**	**$ 10,454**	**$ 8,013**	**$ 8,979**	**$ 11,601**	**$ 9,654**	**$ 7,977**	**$ 6,449**	**$ 6,138**	**$ 6,906**	**$ 5,918**	**$ 5,880**	**$ 9,628**	**$ 97,596**	-
57	Augmentation Power Purchase total	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 94,913	318
58	Balancing Power Purchase sub-total	$ 2,777	$ 4,766	$ 5,905	$ 1,368	$ 3,113	$ 591	$ 75	$ 33	$ 33	$ 430	$ 1,302	$ 6,327	$ 26,720	145
59	Other Power Purchase total	$ 2,112	$ 2,047	$ 2,112	$ 2,112	$ 1,909	$ 2,109	$ 2,044	$ 2,112	$ 2,044	$ 2,112	$ 2,112	$ 2,044	$ 24,869	74
60	**Power Purchases**	**$ 12,798**	**$ 14,722**	**$ 15,926**	**$ 11,390**	**$ 12,931**	**$ 10,609**	**$ 10,029**	**$ 10,055**	**$ 9,987**	**$ 10,451**	**$ 11,323**	**$ 16,281**	**$ 146,501**	**537**

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														2013	
2	**Category**	**201210**	**201211**	**201212**	**201301**	**201302**	**201303**	**201304**	**201305**	**201306**	**201307**	**201308**	**201309**	**$ (000's)**	**aMW**
3	Composite Revenue	189,911	189,911	189,911	189,911	189,911	189,667	189,667	189,667	189,667	189,667	189,667	189,667	2,277,224	5,052
4	Non-Slice Revenue	(27,379)	(27,379)	(27,379)	(27,379)	(27,379)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(27,330)	(328,205)	-
5	Slice	-	-	-	-	-	-	-	-	-	-	-	-	-	2,072
6	Load Shaping Revenue	772	(11,495)	10,848	21,522	18,965	17,174	26,368	(43,567)	(25,966)	(24,451)	(1,671)	(7,877)	(19,379)	(29)
7	Demand Revenue	1,697	1,201	2,558	3,656	786	5,033	5,226	3,677	3,425	5,521	6,044	3,663	42,486	-
8	Irrigation Rate Discount	-	-	-	-	-	-	-	(2,976)	(4,447)	(5,122)	(4,203)	(2,557)	(19,305)	-
9	Low Density Discount	(2,406)	(1,968)	(2,508)	(2,857)	(2,630)	(3,047)	(1,896)	(2,445)	(2,616)	(3,001)	(2,521)	(4,181)	(32,077)	-
10	Tier 2	2,049	1,986	2,049	2,049	1,851	2,010	2,010	2,010	2,010	2,010	2,010	2,010	24,055	56
11	RSS (Non-Federal)	156	93	57	93	82	20	21	21	21	20	20	94	698	-
12	**PF customers (CHWM) sub-total**	**164,800**	**152,349**	**175,535**	**186,995**	**181,586**	**183,527**	**194,066**	**119,057**	**134,764**	**137,314**	**162,016**	**153,489**	**1,945,498**	**7,151**
13	**DSIs sub-total**	**8,512**	**8,290**	**9,090**	**8,811**	**8,231**	**8,823**	**8,107**	**7,394**	**7,122**	**8,908**	**9,510**	**8,873**	**101,673**	**320**
14	**FPS sub-total**	**226**	**195**	**249**	**298**	**215**	**228**	**228**	**228**	**228**	**228**	**228**	**228**	**2,781**	**8**
15	**Short-term market sales sub-total**	**17,350**	**32,121**	**51,357**	**42,264**	**27,087**	**34,701**	**64,742**	**48,155**	**46,897**	**38,889**	**17,206**	**10,063**	**430,832**	**1,874**
16	**Long Term Contractual Obligations sub-total**	**29**	**6,633**	**6,848**	**6,838**	**6,266**	**3,425**	**3,336**	**79**	**85**	**82**	**62**	**39**	**33,722**	**62**
17	**Canadian Entitlement Return**	-	-	-	-	-	-	-	-	-	-	-	-	-	**505**
18	**Renewable Energy Certificates sub-total**	-	**27**	**2**	-	-	**1,070**	**33**	-	-	-	-	-	**1,132**	-
19	Miscellaneous Credits	31	31	(48)	33	30	119	119	119	119	119	119	119	910	-
20	Load Shaping True up	-	-	-	-	-	-	-	-	-	-	-	1,898	1,898	-
21	Slice True up	-	-	-	-	-	-	-	-	-	-	-	(7,795)	(7,795)	-
22	**Other Sales sub-total**	**31**	**31**	**(48)**	**33**	**30**	**119**	**119**	**119**	**119**	**119**	**119**	**(5,777)**	**(4,986)**	-
23	**Gross Sales**	**$190,948**	**$199,646**	**$243,033**	**$245,239**	**$223,416**	**$231,894**	**$270,630**	**$175,033**	**$189,215**	**$185,541**	**$189,141**	**$166,915**	**$2,510,651**	**9,920**
24	GTA Delivery charge	160	208	219	249	193	165	165	165	165	165	165	165	2,184	-
25	Energy Efficiency Revenues	146	329	468	138	168	703	1,287	1,287	1,287	1,287	1,287	1,287	9,675	-
26	Irrigation Pumping Power	79	1	1	1	1	9	84	181	216	275	256	181	1,284	174
27	Reserve Energy	804	804	804	804	804	804	804	804	804	804	804	804	9,645	3
28	Downstream Benefits	471	471	471	471	471	508	508	508	508	508	508	508	5,909	-
29	Upper Baker Revenues	-	96	101	99	101	-	-	-	-	-	-	-	397	1
30	**Miscellaneous Revenues**	**$1,660**	**$1,908**	**$2,064**	**$1,761**	**$1,738**	**$2,189**	**$2,847**	**$2,945**	**$2,979**	**$3,039**	**$3,020**	**$2,944**	**$29,094**	**178**
31	Regulating Reserve	550	550	550	550	550	550	550	550	550	550	550	550	6,601	-
32	Variable Energy Resource Balancing Service Reserve - Wind	4,489	4,489	4,679	4,679	4,711	4,707	4,468	4,468	4,591	4,591	4,703	4,703	55,277	-
33	Variable Energy Resource Balancing Service for Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	-	-	-	-	-	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(1,680)	-
35	VERBS Supplemental Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	VERBS for Solar	-	-	-	-	-	1	1	1	1	1	1	1	9	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	381	381	381	381	381	381	381	381	381	381	381	381	4,576	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	98	98	98	98	98	98	98	98	98	98	98	98	1,177	-
39	Adjustment for Settlement for Generation Inputs and Transmission Ancillary and Control Area Service Rates	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Operating Reserve - Spinning	2,076	2,196	2,621	2,745	2,433	2,416	2,367	2,293	2,469	2,457	2,203	2,007	28,284	-
41	Operating Reserve - Supplemental	1,764	1,866	2,228	2,333	2,068	2,053	2,011	1,949	2,098	2,088	1,872	1,705	24,036	-
42	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	(41)	-	-	-	-	-	-	(41)	-
43	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	(35)	-	-	-	-	-	-	(35)	-
44	Synchronous Condensing	157	157	157	157	157	157	157	157	157	157	157	157	1,880	-
45	Generation Dropping	31	31	31	31	31	31	31	31	31	31	31	31	377	-
46	Energy Imbalance	638	629	438	416	295	118	221	79	170	208	(4)	(46)	3,161	-
47	Generation Imbalance	-	-	-	-	-	869	1,061	737	751	1,011	417	566	5,411	-
48	Persistent Deviation - Energy Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Persistent Deviation - Generation Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Station Service	246	246	246	246	246	246	246	246	246	246	246	246	2,950	9
51	Redispatch	48	1	2	-	0	33	33	33	33	33	33	33	285	-
52	COE/Reclamation Network/Delivery Facilities Segmentation	592	592	592	592	592	592	592	592	592	592	592	592	7,105	-
53	Operating Reserve - Energy	55	114	60	82	58	74	53	45	48	128	99	86	901	-
54	**Generation Inputs / Inter-business line**	**11,126**	**11,350**	**12,084**	**12,310**	**11,621**	**12,254**	**12,355**	**11,745**	**12,261**	**12,636**	**11,479**	**11,210**	**142,432**	**9**
55	4(h)(10)(c)	5,796	15,223	4,387	4,466	6,175	10,575	8,040	5,831	5,796	5,796	5,538	9,026	86,649	-
56	Colville and Spokane Settlements	383	383	383	383	383	383	383	383	383	383	383	383	4,600	-
57	**Treasury Credits**	**6,179**	**15,606**	**4,770**	**4,850**	**6,559**	**10,958**	**8,423**	**6,214**	**6,179**	**6,179**	**5,922**	**9,409**	**91,249**	338
58	Augmentation Power Purchase sub-total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Balancing Power Purchase sub-total	15,074	11,617	11,842	11,230	19,600	28,079	8,405	397	75	895	6,156	6,293	119,664	199
60	Other Power Purchase sub-total	1,007	8,086	9,111	11,637	9,980	9,967	9,340	1,952	1,952	1,952	1,952	1,952	68,885	139
61	**Power Purchases**	**15,137**	**18,759**	**20,984**	**25,185**	**30,806**	**38,692**	**17,764**	**2,349**	**2,026**	**2,846**	**8,108**	**8,245**	**188,549**	**338**
62															
63	* DSI Revenues are split over 12 months of FY. Difference of $9K in 2014 and 2015 is due to rounding. Ties to Table 4.8 Direct Service Industries (DSI) revenues - FY2013 - 2015.														

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														**2014**	
2	**Category**	**201310**	**201311**	**201312**	**201401**	**201402**	**201403**	**201404**	**201405**	**201406**	**201407**	**201408**	**201409**	**$ (000's)**	**aMW**
3	Composite Revenue	192,404	192,404	192,404	192,404	192,404	192,404	192,404	192,404	192,404	192,404	192,404	192,404	2,308,843	6,982
4	Non-Slice Revenue	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(21,558)	(258,691)	-
5	Slice	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Load Shaping Revenue	(516)	(6,585)	14,517	15,040	19,397	10,979	19,850	(29,296)	(17,949)	(17,316)	(4,932)	233	3,422	(54)
7	Demand Revenue	3,865	2,433	5,711	6,097	3,025	3,830	3,322	2,439	1,659	3,580	3,762	3,231	42,954	-
8	Irrigation Rate Discount	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(1,568)	(18,816)	-
9	Low Density Discount	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(2,942)	(35,303)	-
10	Tier 2	458	458	458	458	458	458	458	458	458	458	458	458	5,502	18
11	RSS (Non-Federal)	42	42	42	42	42	42	42	42	42	42	42	42	504	-
12	**PF customers (CHWM) sub-total**	**170,186**	**162,684**	**187,064**	**187,974**	**189,259**	**181,645**	**190,009**	**139,980**	**150,546**	**153,100**	**165,667**	**170,301**	**2,048,415**	**6,945**
13	**DSIs sub-total**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**8,876**	**106,510**	**312**
14	**FPS sub-total**	**244**	**249**	**269**	**279**	**254**	**254**	**239**	**249**	**254**	**264**	**259**	**244**	**3,052**	**8**
15	**Short-term market sales sub-total**	**3,055**	**5,804**	**5,403**	**25,917**	**22,803**	**38,044**	**47,012**	**52,848**	**54,697**	**42,597**	**17,483**	**6,489**	**322,152**	**1,661**
16	**Long Term Contractual Obligations sub-total**	**41**	**5,893**	**6,053**	**6,042**	**5,532**	**3,026**	**2,931**	**79**	**85**	**82**	**62**	**39**	**29,865**	**59**
17	**Canadian Entitlement Return**	-	-	-	-	-	-	-	-	-	-	-	-	-	**500**
18	**Renewable Energy Certificates sub-total**	-	-	-	-	-	**1,061**	-	-	-	-	-	-	**1,061**	-
19	Miscellaneous Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Load Shaping True up	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Slice True up	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	**Other Sales sub-total**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Gross Sales**	**$182,401**	**$183,506**	**$207,665**	**$229,087**	**$226,723**	**$232,906**	**$249,066**	**$202,031**	**$214,458**	**$204,918**	**$192,347**	**$185,948**	**$2,511,055**	**9,485**
24	GTA Delivery charge	155	175	190	195	180	170	160	155	155	165	170	145	2,015	-
25	Energy Efficiency Revenues	988	988	988	988	988	988	988	988	988	988	988	988	11,859	-
26	Irrigation Pumping Power	85	1	1	1	1	10	90	195	235	300	279	196	1,393	174
27	Reserve Energy	727	727	727	727	727	727	727	727	727	727	727	727	8,718	3
28	Downstream Benefits	440	440	440	440	440	440	440	440	440	440	440	440	5,282	-
29	Upper Baker Revenues	-	101	108	105	109	-	-	-	-	-	-	-	422	1
30	**Miscellaneous Revenues**	**$2,395**	**$2,432**	**$2,453**	**$2,456**	**$2,445**	**$2,335**	**$2,405**	**$2,505**	**$2,545**	**$2,619**	**$2,603**	**$2,496**	**$29,689**	**178**
31	Regulating Reserve	505	505	505	505	505	505	505	505	505	505	505	505	6,058	-
32	Variable Energy Resource Balancing Service Reserve - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Variable Energy Resource Balancing Service for Wind	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	4,892	58,705	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	VERBS Supplemental Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	VERBS for Solar	3	3	3	3	3	3	3	3	3	3	3	5	40	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	227	227	227	227	227	227	227	227	227	227	227	227	2,728	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	32	32	32	32	32	32	32	32	32	32	32	32	388	-
39	Adjustment for Settlement for Generation Inputs and Transmission Ancillary and Control Area Service Rates	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(314)	(3,769)	-
40	Operating Reserve - Spinning	1,608	1,657	1,901	1,961	1,716	1,825	1,771	1,934	1,998	1,908	1,722	1,479	21,480	-
41	Operating Reserve - Supplemental	1,473	1,518	1,742	1,797	1,573	1,672	1,623	1,771	1,830	1,749	1,578	1,355	19,680	-
42	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Synchronous Condensing	131	131	131	131	131	131	131	131	131	131	131	131	1,569	-
45	Generation Dropping	28	28	28	28	28	28	28	28	28	28	28	28	333	-
46	Energy Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Generation Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Persistent Deviation - Energy Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Persistent Deviation - Generation Imbalance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Station Service	199	199	199	199	199	199	199	199	199	199	199	199	2,385	9
51	Redispatch	33	33	33	33	33	33	33	33	33	33	33	33	400	-
52	COE/Reclamation Network/Delivery Facilities Segmentation	642	642	642	642	642	642	642	642	642	642	642	642	7,699	-
53	Operating Reserve - Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	**Generation Inputs / Inter-business line**	**9,459**	**9,553**	**10,021**	**10,136**	**9,667**	**9,874**	**9,771**	**10,083**	**10,206**	**10,035**	**9,678**	**9,213**	**117,696**	**9**
55	4(h)(10)(c)	10,011	7,821	10,029	12,393	10,429	8,578	6,319	5,947	6,224	5,648	5,791	7,983	97,173	-
56	Colville and Spokane Settlements	383	383	383	383	383	383	383	383	383	383	383	383	4,600	-
57	**Treasury Credits**	**10,394**	**8,205**	**10,413**	**12,777**	**10,812**	**8,962**	**6,702**	**6,330**	**6,608**	**6,031**	**6,174**	**8,366**	**101,773**	-
58	Augmentation Power Purchase sub-total	516	516	516	516	516	516	516	516	516	516	516	516	6,198	21
59	Balancing Power Purchase sub-total	4,611	4,846	7,633	2,843	2,612	608	56	33	33	240	697	3,208	27,421	156
60	Other Power Purchase sub-total	449	5,999	6,287	6,476	5,972	6,475	6,462	449	436	449	449	436	40,340	87
61	**Power Purchases**	**5,577**	**11,361**	**14,436**	**9,836**	**9,100**	**7,600**	**7,035**	**999**	**985**	**1,206**	**1,663**	**4,160**	**73,958**	**264**
62															
63	* DSI Revenues are split over 12 months of FY. Difference of $9K in 2014 and 2015 is due to rounding														

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														2015	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 193,223	$ 2,318,682	7,011
4	Non-Slice Revenue	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (21,684)	$ (260,204)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 827	$ (4,816)	$ 17,472	$ 17,985	$ 21,977	$ 12,669	$ 21,097	$ (28,955)	$ (17,159)	$ (16,117)	$ (3,691)	$ 1,502	$ 22,791	19
7	Demand Revenue	$ 3,704	$ 1,556	$ 6,847	$ 6,109	$ 3,212	$ 3,817	$ 3,325	$ 1,791	$ 2,364	$ 3,599	$ 3,772	$ 3,290	$ 43,388	-
8	Irrigation Rate Discount	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (1,568)	$ (18,816)	-
9	Low Density Discount	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (3,030)	$ (36,361)	-
10	Tier 2	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 2,147	$ 25,769	75
11	RSS (Non-Federal)	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 63	$ 757	-
12	**PF customers (CHWM) sub-total**	**$ 173,683**	**$ 165,893**	**$ 193,472**	**$ 193,247**	**$ 194,341**	**$ 185,639**	**$ 193,574**	**$ 141,988**	**$ 154,357**	**$ 156,634**	**$ 169,233**	**$ 173,944**	**$ 2,096,006**	**7,105**
13	**DSIs sub-total**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 8,876**	**$ 106,510**	**312**
14	**FPS sub-total**	**$ 249**	**$ 254**	**$ 274**	**$ 284**	**$ 259**	**$ 259**	**$ 244**	**$ 254**	**$ 259**	**$ 269**	**$ 264**	**$ 249**	**$ 3,119**	**9**
15	**Short-term market sales sub-total**	**$ 6,239**	**$ 5,736**	**$ 12,098**	**$ 28,197**	**$ 28,179**	**$ 40,559**	**$ 44,067**	**$ 46,400**	**$ 50,961**	**$ 47,174**	**$ 24,796**	**$ 5,911**	**$ 340,317**	**1,654**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**74**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**475**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**-**
19	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
20	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
23	**Gross Sales**	**$189,088**	**$186,652**	**$220,772**	**$236,645**	**$237,187**	**$239,466**	**$249,692**	**$197,598**	**$214,539**	**$213,035**	**$203,231**	**$189,019**	**$2,576,924**	**9,629**
24	GTA Delivery charge	$ 160	$ 180	$ 190	$ 195	$ 180	$ 175	$ 160	$ 155	$ 155	$ 165	$ 170	$ 145	$ 2,030	-
25	Energy Efficiency Revenues	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 1,007	$ 12,083	-
26	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,394	174
27	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
28	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
29	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
30	**Miscellaneous Revenues**	**$2,419**	**$2,464**	**$2,479**	**$2,479**	**$2,466**	**$2,359**	**$2,423**	**$2,524**	**$2,564**	**$2,638**	**$2,622**	**$2,514**	**$29,953**	**178**
31	Regulating Reserve	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 6,058	-
32	Variable Energy Resource Balancing Service Reserve - Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Variable Energy Resource Balancing Service for Wind	$ 4,284	$ 4,284	$ 4,284	$ 4,284	$ 4,284	$ 4,284	$ 4,604	$ 4,604	$ 4,604	$ 4,604	$ 4,604	$ 4,604	$ 53,328	-
34	Committed Intra-Hour Scheduling Pilot Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	VERBS for Solar	$ 5	$ 5	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	$ 74	-
37	Dispatchable Energy Resource Balancing Service Reserve inc	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 227	$ 2,728	-
38	Dispatchable Energy Resource Balancing Service Reserve dec	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 32	$ 388	-
39	Adjustment for Settlement for Generation Inputs and Transmission Ancillary and Control Area Service Rates	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (314)	$ (3,769)	-
40	Operating Reserve - Spinning	$ 1,572	$ 1,637	$ 1,913	$ 2,016	$ 1,763	$ 1,875	$ 1,819	$ 1,983	$ 2,049	$ 1,959	$ 1,769	$ 1,520	$ 21,875	-
41	Operating Reserve - Supplemental	$ 1,440	$ 1,500	$ 1,753	$ 1,847	$ 1,615	$ 1,718	$ 1,666	$ 1,817	$ 1,877	$ 1,795	$ 1,621	$ 1,393	$ 20,042	-
42	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with Avista and Puget	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,569	-
45	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 333	-
46	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Persistent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
49	Persistent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
50	Station Service	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 2,385	9
51	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
52	COE/Reclamation Network/Delivery Facilities Segmentation	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 7,500	-
53	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
54	**Generation Inputs / Inter-business line**	**$ 8,767**	**$ 8,892**	**$ 9,422**	**$ 9,618**	**$ 9,135**	**$ 9,349**	**$ 9,562**	**$ 9,876**	**$ 10,003**	**$ 9,831**	**$ 9,466**	**$ 8,989**	**$ 112,910**	**9**
55	4(h)(10)(c)	$ 10,071	$ 7,630	$ 8,595	$ 11,218	$ 9,271	$ 7,593	$ 6,065	$ 5,755	$ 6,523	$ 5,534	$ 5,496	$ 9,244	$ 92,996	-
56	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
57	**Treasury Credits**	**$ 10,454**	**$ 8,013**	**$ 8,979**	**$ 11,601**	**$ 9,654**	**$ 7,977**	**$ 6,449**	**$ 6,138**	**$ 6,906**	**$ 5,918**	**$ 5,880**	**$ 9,628**	**$ 97,596**	**-**
58	Augmentation Power Purchase sub-total	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 7,909	$ 94,913	318
59	Balancing Power Purchase sub-total	$ 2,777	$ 4,766	$ 5,905	$ 1,368	$ 3,113	$ 591	$ 75	$ 33	$ 33	$ 430	$ 1,302	$ 6,327	$ 26,720	145
60	Other Power Purchase sub-total	$ 2,112	$ 2,047	$ 2,112	$ 2,112	$ 1,909	$ 2,109	$ 2,044	$ 2,112	$ 2,044	$ 2,112	$ 2,112	$ 2,044	$ 24,869	74
61	**Power Purchases**	**$ 12,798**	**$ 14,722**	**$ 15,926**	**$ 11,390**	**$ 12,931**	**$ 10,609**	**$ 10,029**	**$ 10,055**	**$ 9,987**	**$ 10,451**	**$ 11,323**	**$ 16,281**	**$ 146,501**	**537**
62															
63	* DSI Revenues are split over 12 months of FY. Difference of $9K in 2014 and 2015 is due to roundin														

Table 4.3

Composite and Non-slice revenue
FY 2014-2015

	A	B	C	D	E	F	G
1	**Billing Determinants**	**FY 2014**		**FY 2015**		**Rate Period**	
2	TOCA..	98.112390	A)	98.530480	A)	98.321435	
3	Non-slice TOCA..	71.484980	B)	71.903070	B)	71.694025	
4	Slice Percentage..	26.627410		26.627410		26.627410	
5							
6	**Annual TRM Rates ($000)**	**FY 2014**		**FY 2015**		**Rate Period**	
7	Composite..	$ 23,280		$ 23,785		$ 23,533	C)
8	Non-Slice..	$ (3,314)		$ (3,921)		$ (3,619)	D)
9	Slice..	$ -		$ -		$ -	
10							
11	**Yearly Revenues (Yearly TOCA * Rate Period rate)**	**FY 2014**		**FY 2015**			
12	Composite (A * C)..	$ 2,308,843	E)	$ 2,318,682	E)		
13	Non-Slice (B * D)..	$ (258,691)	E)	$ (260,204)	E)		
14	Slice..	$ -		$ -			
15							
16	**Monthly Revenues (Yearly Revenues / 12)**	**FY 2014**		**FY 2015**			
17	Composite (E / 12)..	$ 192,404		$ 193,223			
18	Non-Slice (E / 12)..	$ (21,558)		$ (21,684)			
19	Slice..	$ -		$ -			
20							
21	*Ties to Table 4.2, Revenue at Proposed Rates, lines 3-4*						

Table 4.4

Load Shaping and Demand revenue
FY 2014-2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**FY 2014**		**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Total**
2	Load Shaping HLH (MWh)	A)	(134,034)	(288,696)	56,604	30,769	217,949	157,996	493,964	(1,090,273)	(691,177)	(649,793)	(247,554)	(126,011)	
3	Load Shaping LLH (MWh)	B)	135,568	117,707	370,263	452,455	371,149	247,116	354,154	(489,307)	(153,660)	101,867	128,286	160,336	
4	Load Shaping HLH Rate ($/MWh)	C)	$ 31.59	$ 35.56	$ 38.84	$ 37.80	$ 36.89	$ 30.23	$ 25.76	$ 21.00	$ 22.73	$ 30.49	$ 33.96	$ 33.65	
5	Load Shaping LLH Rate ($/MWh)	D)	$ 27.43	$ 31.27	$ 33.27	$ 30.67	$ 30.60	$ 25.10	$ 20.12	$ 13.08	$ 14.57	$ 24.50	$ 27.09	$ 27.90	
6	Load Shaping Revenue (A * C) + (B * D)		$ (515,507)	$ (6,585,349)	$ 14,517,152	$ 15,039,846	$ 19,397,298	$ 10,978,832	$ 19,850,075	$ (29,295,862)	$ (17,949,286)	$ (17,316,430)	$ (4,931,679)	$ 233,112	$ 3,422,202
7															
8	Demand (kW)	E)	414,281	231,725	497,878	545,873	277,505	428,851	436,524	393,447	246,843	397,336	375,055	325,095	
9	Demand Rate ($/kW-mo.)	F)	$ 9.33	$ 10.50	$ 11.47	$ 11.17	$ 10.90	$ 8.93	$ 7.61	$ 6.20	$ 6.72	$ 9.01	$ 10.03	$ 9.94	
10	Demand Revenue (E * F)		$ 3,865,239	$ 2,433,113	$ 5,710,663	$ 6,097,405	$ 3,024,807	$ 3,829,640	$ 3,321,945	$ 2,439,374	$ 1,658,785	$ 3,579,998	$ 3,761,798	$ 3,231,449	$ 42,954,216
11															
12															
13															
14															
15	**FY 2015**		**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Total**
16	Load Shaping HLH (MWh)	A)	(108,123)	(296,263)	140,172	77,500	261,027	192,398	525,249	(1,100,658)	(648,110)	(626,861)	(225,004)	(103,440)	
17	Load Shaping LLH (MWh)	B)	154,679	182,905	361,531	490,889	403,519	273,036	376,063	(446,577)	(166,623)	122,275	145,803	178,587	
18	Load Shaping HLH Rate ($/MWh)	C)	$ 31.59	$ 35.56	$ 38.84	$ 37.80	$ 36.89	$ 30.23	$ 25.76	$ 21.00	$ 22.73	$ 30.49	$ 33.96	$ 33.65	
19	Load Shaping LLH Rate ($/MWh)	D)	$ 27.43	$ 31.27	$ 33.27	$ 30.67	$ 30.60	$ 25.10	$ 20.12	$ 13.08	$ 14.57	$ 24.50	$ 27.09	$ 27.90	
20	Load Shaping Revenue (A * C) + (B * D)		$ 827,245	$ (4,815,652)	$ 17,472,405	$ 17,985,050	$ 21,976,958	$ 12,669,386	$ 21,096,789	$ (28,955,043)	$ (17,159,230)	$ (16,117,231)	$ (3,691,307)	$ 1,501,826	$ 22,791,196
21															
22	Demand (kW)	E)	396,974	148,227	596,970	546,930	294,699	427,479	436,951	288,912	351,831	399,422	376,079	331,021	
23	Demand Rate ($/kW-mo.)	F)	$ 9.33	$ 10.50	$ 11.47	$ 11.17	$ 10.90	$ 8.93	$ 7.61	$ 6.20	$ 6.72	$ 9.01	$ 10.03	$ 9.94	
24	Demand Revenue (E * F)		$ 3,703,763	$ 1,556,383	$ 6,847,243	$ 6,109,203	$ 3,212,217	$ 3,817,390	$ 3,325,194	$ 1,791,253	$ 2,364,303	$ 3,598,791	$ 3,772,069	$ 3,290,348	$ 43,388,157
25															
26	*Ties to Table 4.2, Revenue at Proposed Rates, lines 6-7*														

Table 4.5

Irrigation Rate Discount (IRD)
FY 2014-2015

	A	B	C	D	E	F	G	H
1	**Irrigation Rate Discount**							
2	IRD Percentage	37.06%						
3	Total Irrigation Load (MWh)	1,881,605						
4	RT1SC	7,116						
5	Annual NonSlice Dollar Amount	2,067,647						
6	Average Hours in Rate Period	8784						
7	**Implied Discount ($/MWh)**	**10.00**		A)				
8								
9								
10								
11	**FY 2014**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**		**TOTAL**
12	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
13	IRD credit ($) (A * B)	$ (2,900,411)	$ (4,334,636)	$ (4,992,105)	$ (4,096,691)	$ (2,492,203)		**$ (18,816,045)**
14								
15								
16	**FY2015**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**		**TOTAL**
17	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
18	IRD credit ($) (A * B)	$ (2,900,411)	$ (4,334,636)	$ (4,992,105)	$ (4,096,691)	$ (2,492,203)		**$ (18,816,045)**
19								
20								
21	*Ties to Table 4.2, Revenue at Proposed Rates, line 8*							

Table 4.6

Low Density Discount (LDD)
FY 2014-2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Customer Charge LDD	**FY 2014**	**FY 2015**												
2	TOCA LDD Offset %...	1.63%	1.67%	**A)**											
3															
4	TRM Costs after Adjustments														
5	Composite...	$ 2,308,843	$ 2,318,682												
6	Non-Slice..	$ (258,691)	$ (260,204)												
7	Slice..	$ -	$ -												
8		$ 2,050,152	$ 2,058,478	**B)**											
9															
10	LDD discount - Composite portion (A * B)..............................	$ 33,355.72	$ 34,311.86	**C)**											
11	LDD discount (Demand/Load Shaping portion)........................	$ 1,947.38	$ 2,049.27	**D) below**											
12	**Total LDD discount (C + D)..**	**$ 35,303.10**	**$ 36,361.13**												
13															
14	**Demand and Load Shaping Discount Detail**														
15	**FY 2014**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**		
16	Demand BD (kW)	18,568	14,950	23,262	25,171	15,051	16,004	18,485	14,092	10,835	17,923	15,963	12,949		
17	Load Shaping BD HLH (MWh)	(4,470)	(9,070)	1,347	(1,091)	4,321	647	11,098	(21,976)	(9,099)	(7,917)	603	(2,231)		
18	Load Shaping BD LLH (MWh)	672	(899)	5,498	7,042	6,561	1,114	6,785	(9,927)	(1,333)	6,478	4,538	2,734		
19	Demand Rate	$ 9.33	$ 10.50	$ 11.47	$ 11.17	$ 10.90	$ 8.93	$ 7.61	$ 6.20	$ 6.72	$ 9.01	$ 10.03	$ 9.94		
20	Load Shaping Rate (HLH)	$ 31.59	$ 35.56	$ 38.84	$ 37.80	$ 36.89	$ 30.23	$ 25.76	$ 21.00	$ 22.73	$ 30.49	$ 33.96	$ 33.65		
21	Load Shaping Rate (LLH)	$ 27.43	$ 31.27	$ 33.27	$ 30.67	$ 30.60	$ 25.10	$ 20.12	$ 13.08	$ 14.57	$ 24.50	$ 27.09	$ 27.90		
22	LDD credit (Demand/Load Shaping portion)	$ 50,482	$ (193,665)	$ 502,049	$ 455,912	$ 524,236	$ 190,440	$ 563,057	$ (503,970)	$ (153,434)	$ 78,817	$ 303,521	$ 129,937	$ 1,947,384	
23														$ 1,947.38	**D)**
24	**FY 2015**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**		
25	Demand BD (kW)	19,913	12,088	29,632	27,068	17,101	16,862	19,746	11,544	15,783	19,235	16,592	13,685		
26	Load Shaping BD HLH (MWh)	(5,103)	(9,629)	1,188	(934)	4,916	285	11,326	(22,929)	(9,630)	(7,904)	166	(1,993)		
27	Load Shaping BD LLH (MWh)	361	(1,035)	5,273	7,893	7,273	860	6,930	(10,558)	(1,737)	6,590	4,228	2,735		
28	Demand Rate	$ 9.33	$ 10.50	$ 11.47	$ 11.17	$ 10.90	$ 8.93	$ 7.61	$ 6.20	$ 6.72	$ 9.01	$ 10.03	$ 9.94		
29	Load Shaping Rate (HLH)	$ 31.59	$ 35.56	$ 38.84	$ 37.80	$ 36.89	$ 30.23	$ 25.76	$ 21.00	$ 22.73	$ 30.49	$ 33.96	$ 33.65		
30	Load Shaping Rate (LLH)	$ 27.43	$ 31.27	$ 33.27	$ 30.67	$ 30.60	$ 25.10	$ 20.12	$ 13.08	$ 14.57	$ 24.50	$ 27.09	$ 27.90		
31	LDD credit(Demand/Load Shaping portion)	$ 34,506	$ (247,843)	$ 561,447	$ 509,125	$ 590,311	$ 180,787	$ 581,476	$ (548,038)	$ (138,143)	$ 93,769	$ 286,598	$ 145,279	$ 2,049,273	
32														$ 2,049.27	**D)**
33	**LDD credit is negative revenue*														
34	*Ties to Table 4.2, Revenue at Proposed Rates, line 9*														

Table 4.7

Tier 2 Revenue
FY 2014-2015

	A	B	C
1	**Fiscal Year**		
2	**Rate Period**	**FY2014**	**FY2015**
3			
4	Base Power Purchase Cost	$ 4,664,525	$ 6,852,510
5	Rate Design Components	$ 190,384	$ 330,968
6	Other Costs	$ -	$ -
7	Rate $/MWh	**$ 35.58**	**$ 39.65**
8	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (168,912)	$ (294,570)
9	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
10	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (21,472)	$ (36,398)
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	$ 5,093,173	$ 9,621,152
14	Remarketing Credit	$ -	$ -
15	Remarketing Charge	$ -	$ -
16	Forecast Power Purchase Costs	$ 3,527	$ 121,120
17			
18			
19	Base Power Purchase Cost	$ 291,533	$ 1,713,456
20	Rate Design Components	$ 15,296	$ 19,995
21	Other Costs	$ -	$ -
22	Rate $/MWh	**$ 35.58**	**$ 41.62**
23	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,571)	$ (17,796)
24	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
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	$ 409,206	$ 610,121
29	Remarketing Credit	$ -	$ -
30	Remarketing Charge	$ -	$ 53,698
31	Forecast Power Purchase Costs	$ 1,519	$ -
32			
33	Base Power Purchase Cost		$ 16,090,105
34	Rate Design Components		$ 549,624
35	Other Costs		$ -
36	Rate $/MWh		**$ 41.56**
37	Tier 2 Composite Overhead Adjustment Debit/(Credit)		$ (489,180)
38	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)		$ -
39	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)		$ (60,444)
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		$ 16,747,073
43			
44	Total Tier 2 Revenue Collection Before Remarking Charge/Credit	$ 5,502,380	$ 26,978,346
45	Total Tier 2 Remarketing Charge	$ -	$ (1,263,781)
46	Total Tier 2 Remarketing Credit	$ -	$ 53,698
47	**Total Tier 2 Revenue Collection**	**$ 5,502,380**	**$ 25,768,263**
48			
49	*Ties to Table 4.2, Revenue at Proposed Rates, line 10*		

Table 4.8

Direct Service Industries (DSI) Revenues
FY 2013-2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**FY 2013**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
2	HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
3	LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.8	34.24	
4	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	
5															
6	HLH consumption (MWh)	D)	138,215	127,886	127,930	132,957	122,807	133,328	133,080	133,328	128,200	133,328	138,456	119,808	1,569,323
7	LLH consumption (MWh)	E)	100,141	102,950	110,134	105,159	92,392	104,942	97,432	105,124	102,560	105,124	99,996	104,832	1,230,786
8	Demand (kW)	F)	-	-	-	-	-	-	-	-	-	-	-	-	-
9															
10	HLH revenues (A * D)	G)	5,322,660	4,990,112	5,341,078	5,408,691	5,106,315	5,362,452	5,080,994	4,761,143	4,694,684	5,695,772	6,230,520	5,283,533	63,277,953
11	LLH revenues (B * E)	H)	3,189,491	3,299,548	3,748,961	3,401,894	3,124,697	3,460,987	3,026,238	2,633,356	2,427,595	3,212,589	3,279,869	3,589,448	38,394,673
12	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
13	TOTAL forecast revenues (G + H + I)	J)	$ 8,512,151	$ 8,289,659	$ 9,090,039	$ 8,810,584	$ 8,231,013	$ 8,823,439	$ 8,107,232	$ 7,394,499	$ 7,122,279	$ 8,908,362	$ 9,510,389	$ 8,872,980	$ 101,672,626
14															
15															
16	**FY 2014 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
17	HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
18	LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.80	34.24	
19	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	
20															
21	HLH consumption (MWh)	D)	133,255	122,936	127,343	128,590	118,443	132,274	128,262	126,908	126,346	127,039	131,418	121,544	1,524,358
22	LLH consumption (MWh)	E)	98,498	102,858	103,914	103,216	91,703	99,560	96,514	105,075	97,418	105,268	100,999	103,741	1,208,764
23	Demand (kW)	F)													
24															
25	HLH revenues (A * D)	G)	5,131,650	4,796,963	5,316,570	5,231,041	4,924,860	5,320,060	4,897,043	4,531,885	4,626,791	5,427,106	5,913,810	5,360,090	61,477,869
26	LLH revenues (B * E)	H)	3,137,161	3,296,599	3,537,233	3,339,038	3,101,395	3,283,489	2,997,725	2,632,129	2,305,884	3,216,990	3,312,767	3,552,092	37,712,501
27	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
28	TOTAL revenues (G + H + I)		$ 8,268,811	$ 8,093,562	$ 8,853,803	$ 8,570,079	$ 8,026,255	$ 8,603,549	$ 7,894,768	$ 7,164,013	$ 6,932,675	$ 8,644,096	$ 9,226,577	$ 8,912,182	$ 99,190,371
29															
30	**FY 2015 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
31	HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
32	LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.80	34.24	
33	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	
34															
35	HLH consumption (MWh)	D)	133,254	122,936	127,343	128,589	118,443	132,274	128,263	126,907	126,345	127,040	131,419	121,544	1,524,357
36	LLH consumption (MWh)	E)	98,499	102,859	103,914	103,216	91,703	99,561	96,514	105,076	97,418	105,268	100,999	103,741	1,208,766
37	Demand (kW)	F)													
38															
39	HLH revenues (A * D)	G)	5,131,618	4,796,964	5,316,589	5,231,019	4,924,848	5,320,062	4,897,089	4,531,856	4,626,763	5,427,133	5,913,834	5,360,077	61,477,853
40	LLH revenues (B * E)	H)	3,137,184	3,296,630	3,537,228	3,339,029	3,101,385	3,283,516	2,997,716	2,632,145	2,305,889	3,216,984	3,312,767	3,552,091	37,712,563
41	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
42	TOTAL revenues (G + H + I)		$ 8,268,802	$ 8,093,594	$ 8,853,817	$ 8,570,047	$ 8,026,233	$ 8,603,578	$ 7,894,804	$ 7,164,001	$ 6,932,652	$ 8,644,117	$ 9,226,602	$ 8,912,168	$ 99,190,416
43															
44	**FY 2014 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
45	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	
46	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	
47	Demand rate (kw/Mo)	C)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94	
48															
49	HLH consumption (MWh)	D)	133,255	122,936	127,343	128,590	118,443	132,274	128,262	126,908	126,346	127,039	131,418	121,544	1,524,358
50	LLH consumption (MWh)	E)	98,498	102,858	103,914	103,216	91,703	99,560	96,514	105,075	97,418	105,268	100,999	103,741	1,208,764
51															
52															
53	HLH revenues (A * D)	G)	5,559,399	5,616,946	6,235,987	6,163,319	5,569,190	5,338,579	4,603,323	3,950,646	4,151,730	5,160,324	5,794,220	5,321,196	63,464,857
54	LLH revenues (B * E)	H)	3,699,585	4,258,321	4,509,868	4,211,213	3,735,063	3,507,499	2,919,549	2,438,791	2,406,225	3,645,431	3,759,183	3,945,270	43,035,996
55	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
56	TOTAL revenues (G + H + I)		$ 9,258,983	$ 9,875,267	$ 10,745,854	$ 10,374,532	$ 9,304,253	$ 8,846,077	$ 7,522,872	$ 6,389,437	$ 6,557,954	$ 8,805,755	$ 9,553,402	$ 9,266,467	$ 106,500,853
57															
58	**FY 2015 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
59	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	
60	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	
61	Demand rate (kw/Mo)	C)	9.33	10.50	11.47	11.17	10.90	8.93	7.61	6.20	6.72	9.01	10.03	9.94	
62															
63	HLH consumption (MWh)	D)	133,254	122,936	127,343	128,589	118,443	132,274	128,263	126,907	126,345	127,040	131,419	121,544	1,524,357
64	LLH consumption (MWh)	E)	98,499	102,859	103,914	103,216	91,703	99,561	96,514	105,076	97,418	105,268	100,999	103,741	1,208,766
65															
66															
67	HLH revenues (A * D)	G)	5,559,364	5,616,948	6,236,009	6,163,292	5,569,176	5,338,581	4,603,366	3,950,621	4,151,704	5,160,350	5,794,244	5,321,183	63,464,838
68	LLH revenues (B * E)	H)	3,699,612	4,258,361	4,509,862	4,211,202	3,735,050	3,507,528	2,919,540	2,438,806	2,406,230	3,645,424	3,759,183	3,945,269	43,036,066
69	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
70	TOTAL revenues (G + H + I)		$ 9,258,976	$ 9,875,309	$ 10,745,871	$ 10,374,494	$ 9,304,226	$ 8,846,109	$ 7,522,906	$ 6,389,427	$ 6,557,934	$ 8,805,774	$ 9,553,427	$ 9,266,452	$ 106,500,904
71															
72	*Ties to Table 4.1, Revenue at Current Rates, and 4.2, Revenue at Proposed Rates, line 13*														

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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

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Table Descriptions

Table 8.1 CY 2011 - 2012 Two-Year Average Exchange Loads (MWh)
Table lists the monthly two-year average Exchange Loads based on actual loads as submitted by Exchanging Utilities.

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

Table 8.1

CY 2011 - 2012 Two-Year Average Exchange Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**FY 2014**
2	Avista	247,532	293,593	397,847	447,124	408,529	383,838	334,246	294,458	255,741	250,334	279,308	274,995	3,867,545
3	Idaho Power	506,389	425,644	512,460	619,031	556,535	522,929	440,655	421,511	480,504	587,718	698,318	655,490	6,427,187
4	NorthWestern	45,811	52,240	63,990	71,513	65,563	62,413	55,101	49,399	48,469	49,960	52,290	51,445	668,193
5	PacifiCorp	617,818	685,893	913,836	1,032,585	858,161	827,288	717,348	653,672	662,139	749,504	782,164	734,731	9,235,141
6	PGE	583,743	679,516	881,485	991,771	866,512	846,193	721,344	631,204	594,476	595,660	630,762	640,972	8,663,639
7	Puget Sound Energy	787,019	1,029,176	1,262,776	1,392,911	1,271,958	1,260,518	1,056,625	900,165	814,046	744,776	752,190	751,655	12,023,815
8	Clark	187,013	246,910	313,761	297,446	243,490	242,611	192,056	175,857	151,511	172,487	166,365	150,864	2,540,370
9	Snohomish	219,546	233,774	279,666	369,677	422,784	414,124	389,154	345,164	294,725	257,748	234,302	221,635	3,682,299
10														
11		**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**FY 2015**
12	Avista	247,532	293,593	397,847	447,124	408,529	383,838	334,246	294,458	255,741	250,334	279,308	274,995	3,867,545
13	Idaho Power	506,389	425,644	512,460	619,031	556,535	522,929	440,655	421,511	480,504	587,718	698,318	655,490	6,427,187
14	NorthWestern	45,811	52,240	63,990	71,513	65,563	62,413	55,101	49,399	48,469	49,960	52,290	51,445	668,193
15	PacifiCorp	617,818	685,893	913,836	1,032,585	858,161	827,288	717,348	653,672	662,139	749,504	782,164	734,731	9,235,141
16	PGE	583,743	679,516	881,485	991,771	866,512	846,193	721,344	631,204	594,476	595,660	630,762	640,972	8,663,639
17	Puget Sound Energy	787,019	1,029,176	1,262,776	1,392,911	1,271,958	1,260,518	1,056,625	900,165	814,046	744,776	752,190	751,655	12,023,815
18	Clark	185,747	245,239	311,637	295,432	241,841	240,969	190,756	174,667	150,486	171,319	165,239	149,843	2,523,175
19	Snohomish	221,156	235,488	281,717	374,234	427,996	419,229	393,951	349,419	298,358	260,926	237,189	224,368	3,724,028
20														
21	Note: Monthly REP Residential Exchange Loads for the IOUs are the average of the 2-years of historical loads as defined in the REP Settlement, COU Residential Exchange Loads are from the forecasted loads included in each COU's ASC filing.													

Table 8.2

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

	A	B	C
1		**FY 2014**	**FY 2015**
2	Avista	$ 57.05	$ 57.05
3	Idaho Power	$ 50.22	$ 50.22
4	NorthWestern	$ 70.65	$ 70.65
5	PacifiCorp	$ 65.61	$ 65.61
6	PGE	$ 68.99	$ 68.99
7	Puget Sound Energy	$ 76.83	$ 76.83
8	Clark	$ 49.91	$ 49.91
9	Snohomish	$ 45.27	$ 45.27
10			
11	Note: Forecasted ASCs are determined through the ASC review process.		

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