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

2012 BPA Final Proposal

Power Rates Study Documentation

July 2011

BP-12-FS-BPA-01A

2012 POWER RATES STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS AND SHORT FORMS

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
Commission	Federal Energy Regulatory Commission
COSA	Cost of Service Analysis
COU	consumer-owned utility
Corps or USACE	U.S. Army Corps of Engineers
Council	Northwest Power and Conservation Council
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
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	Hydro Simulation (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
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
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
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
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)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load

TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE or Corps	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
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

DOCUMENTATION FOR THE
2012 POWER RATES STUDY

INTRODUCTION

The Power Rates Study (PRS) Documentation shows the details of the calculation of the power rates.

Section 1 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 contains ratemaking tables that are the output of the Rate Analysis Model (RAM2012). The RAM2012 is a group of computer applications that perform most of the computations that determine BPA's power rates. The output tables of RAM2012 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 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 II.C.

Section 3 documents the calculations of the Demand rate and Load Shaping rates. The section includes the results of the Tier 2 and Resource Support Service (RSS) modules of RAM. The Tier 2 module results include the 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 the Resource Shaping Charge, the RSS rates and charges, the Resource Shaping charge, the Transmission Scheduling Service charge, and the grandfathered Generation Management Service charge. This section also includes calculations and data for the Irrigation Rate Discount. Lastly, this section includes several resource examples that provide a greater level of detail on how the Resource Support Service module calculates rates and charges for different resource types.

Section 4 documents revenue forecasts at both current and proposed rates for the rate period, FY 2012-2013, and at current rates for the period immediately proceeding the two-year rate period, FY 2011.

Section 5 documents Residential Exchange Loads and costs, and Forecast Average System Costs (ASCs).

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SECTION 1: RATE PROCESS MODELING

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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 power rate development process.

POWER LOADS AND RESOURCES STUDY (BP-12-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 allocation factors used to apportion costs and 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), as detailed in the Power Loads and Resources Study. BPA uses HYDSIM to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for the 70 water years (October 1928 through September 1998). The hydro regulation study uses individual project operating characteristics to determine energy production expected from each specific project. Physical characteristics of each project come from 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 the physical characteristics along with power and non-power operating requirements to provide project-by-project monthly energy generation estimates for the Federal and non-Federal system regulated hydro projects that vary by water year. The HYDSIM hydrogregulation study incorporates the power and non-power operating requirements expected to be in effect during the rate period, including those described in the NOAA Fisheries FCRPS Biological Opinion (BiOp) regarding salmon and steelhead, published May 5, 2008; the U.S. Fish and Wildlife Service (USFWS) FCRPS BiOp regarding bull trout and sturgeon, published December 20, 2000; the USFWS Libby BiOp regarding bull trout and sturgeon, published February 18, 2006; relevant operations described in the Northwest Power and Conservation Council's Fish and Wildlife Program;

and other fish mitigation measures. The Federal system hydro generation is used in the Federal system loads and resources balance and is detailed in the Power Loads and Resources Study. Refer to the Power Loads and Resources Study, BP-12-FS-BPA-03 for more details.

Federal System Loads and Resources Balance

The Federal system loads and resources 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-12-FS-BPA-02):

The Power Revenue Requirement Study provides 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-12-FS-BPA-04):

Secondary Energy Revenue Forecast

The Risk Analysis Model (RiskMod) is used to forecast the secondary energy revenues, balancing power purchase expenses, and augmentation purchase expenses. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim and RevSim, a model that calculates net revenues. After accounting for all loads and resources (including augmentation purchases), RiskMod 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 70 years of historical streamflow conditions (1929-1998). Inputs are forecast loads, non-hydro resources, and varying hydro generation. RiskMod uses results from two hydroregulation models, Hydro Simulation (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. RiskMod applies HLH and LLH monthly spot market prices supplied by the AURORA$_{xmp}$ model (see description below) 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 RiskMod. RiskMod 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 AURORA 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

The Risk Analysis Model (RiskMod) and Non-Operating Risk Model (NORM) are used to quantify BPA's net revenue risk. RiskMod 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. The results from RiskMod 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 TPP (the probability of making all planned Treasury payments during the rate period) given the net revenue risks quantified in RiskMod 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 compute the variable cost component of generation input capacity. The market price run is used in the Power Rates Study for:

(a) the prices for surplus sales and balancing purchases in RAM2012,
(b) Load Shaping rate,
(c) Load Shaping True-up rate,
(d) Resource Shaping rate,
(e) Resource Support Service rates,
(f) shaping the Demand rate,
(g) PF Tier 2 Balancing Credit,
(h) PF Unused RHWM Credit,
(i) Tier 1 PF Equivalent Rates,
(j) Melded PF Equivalent Rates,
(k) Balancing Augmentation Credit, and
(l) NR rate design.

It is used in the Power Risk and Market Price Study, for the risk analysis. It is used in the 2012 REP Settlement Evaluation and Analysis Study for calculating utility average system costs.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA. AURORA is an economic fundamentals-based software application that models wholesale electric energy transactions in a competitive pricing system. AURORA 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, AURORA 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-12-FS-BPA-01):
Rate Analysis Model (RAM2012)
RAM2010, a spreadsheet-based model, has three main steps that perform the calculations necessary to develop BPA's power rates: Cost of Service Analysis Step (COSA), Rate Directives Step, and Tiered Rate Methodology Step.

1. Cost of Service Analysis Step. This step complies with BPA's rate directives by determining the costs associated with the three resource pools (Federal base system (FBS), residential exchange, and new resources) used to serve sales load, and then allocating 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 Step. 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 Public, 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 RAM2012 performs these rate adjustments. The amount of PF Public rate protection, as well as the levels of the IP and NR rates, are set assuming a settlement of the legal issues associated with the Residential Exchange Program.

3. Rate Design Step. In the Rate Directives Step, costs are allocated to the various rate pools, including the PF Public rate pool. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. Additional processing is required before the PF Public rate can be designed. The allocation of costs and credits performed in the COSA Step and Rate Directives Step is insufficient to inform the TRM rate design of the PF Public rate. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. RAM2012 accomplishes this different cost allocation through a process of mapping costs and credits to the cost pools. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2012.

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. These services include Diurnal Flattening Service (DFS), Secondary Crediting Service (SCS), Forced Outage Reserves (FOR), 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, 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.

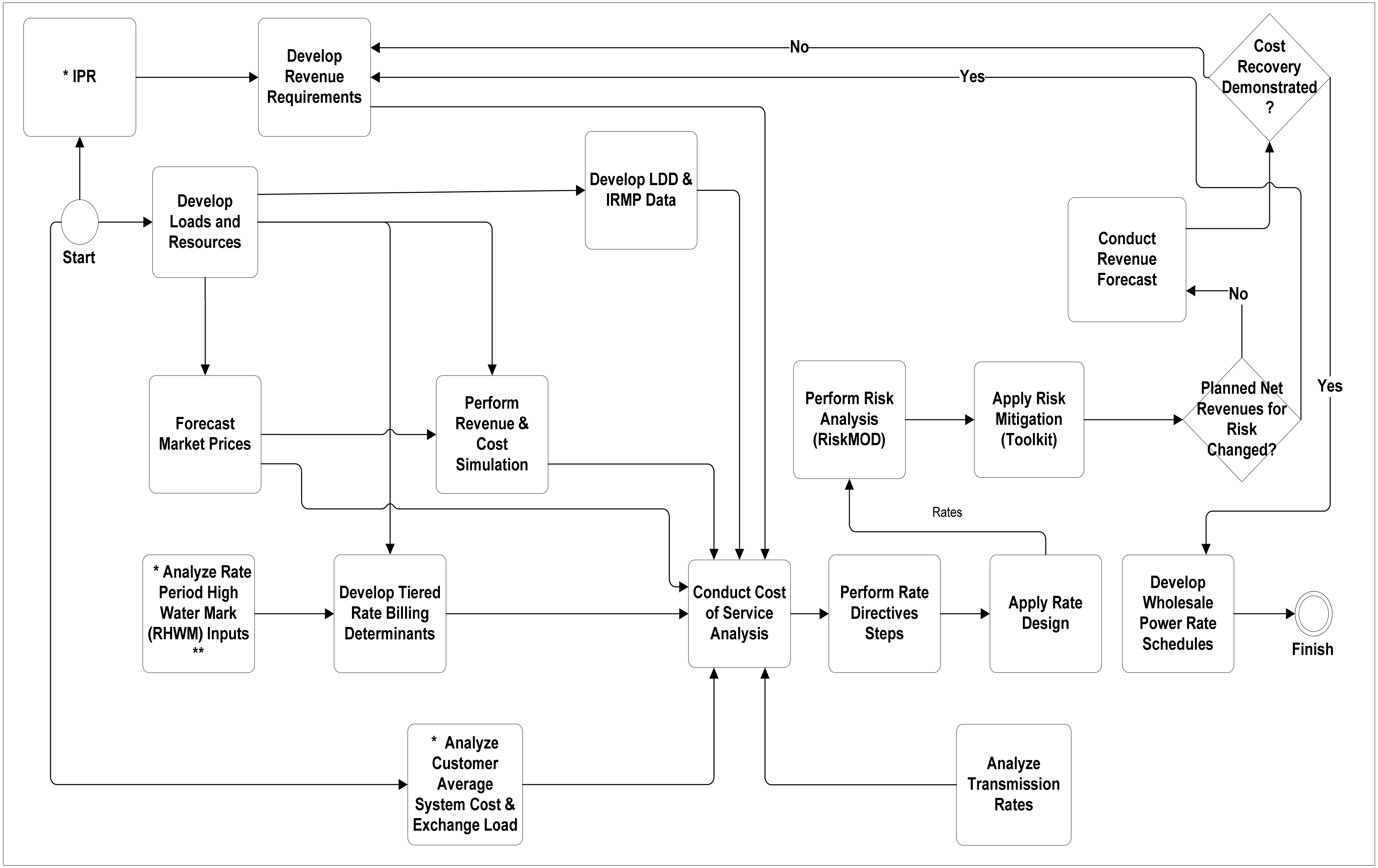
Revenue and Purchased Power Expense Forecast
The Revenue Forecast, section 4 of the Power Rates Study, presents BPA's expected level of revenue as well as purchased power expense for FY 2011-2013. FY 2011 revenues are forecast to estimate level of reserves at the beginning of the rate period. Selected 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 test whether current rates will not recover BPA's revenue requirement and, if not, that 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 purchase power expenses, and 4(h)(10)(C) credits.

FY 2012-2013 Average System Costs (ASCs)
ASCs are used in determining the forecast of REP benefits that exchanging utilities are entitled to receive during the rate period. For purposes of the BP-12 rates, BPA used the Final Report ASCs published by BPA on July 26, 2011. BP-12 rates were established using these Final Report ASCs for FY 2012-2013.

GENERATION INPUTS STUDY (BP-12-FS-BPA-05):
Generation and Reserves Dispatch (GARD) Model
The variable costs associated with providing a quantity of reserves are assessed in the Generation and Reserves Dispatch (GARD) Model using inputs from the HYDSIM model, actual system data, and a pre-processing spreadsheet. The purpose of the GARD model is to calculate the variable costs incurred as a result of operating the Federal Columbia River Power System

(FCRPS) with the necessary reserves to maintain reliability and deploying those reserves to maintain load-resource balance within the BPA Balancing Authority Area. The GARD model analyzes variable costs in two general categories. The first category is the "stand ready" costs, those costs associated with making a project capable of providing reserves. The other is the "deployment costs," those costs incurred when the system uses its reserve capability to actually deliver energy in response to a reserve need. The GARD model produces the following costs associated with standing ready: (1) energy shift, (2) efficiency change, (3) cycling losses, and (4) spill losses. GARD also calculates the following costs associated with deploying reserves: (1) response losses, (2) deployment cycling losses, and (3) deployment spill losses. After the GARD model is run, the megawatthour values for each month and HLH and LLH period of the 70 water year set are passed to RiskMod.

BPA High Level Power Rates Development Process



* These Processes are not part of the 7i- - Rate Process

** RHWM inputs for the BP-12 case will not be available for the initial proposal. Proxy inputs will be developed for the initial proposal.

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SECTION 2: RATE ANALYSIS MODEL

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Description of Ratemaking Tables

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2.3.7.1
Revenue Credits Allocated to FBS Costs (COSA 07-1)
Worksheet allocates FBS related revenue credits as directed by section 7(b) of the Northwest Power Act.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2.4.7
DSI Floor Rate Test 1 (RDS 07)
A test is conducted comparing the IP rate at this stage in the rate-making process to the floor rate established above.

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

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

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

Table 2.4.12
Calculation of Utility Specific PF Exchange Rates and REP Benefits (RDS 12)
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 2.4.13
Allocation of the Increased PF Exchange Costs Due to Settlement (RDS 13)
The difference between the Unconstrained Benefits and the REP Settlement benefits is allocated to the Priority Firm Exchange loads and away from the PF Preference loads. Average power rates are calculated after this reallocation of costs.

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

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

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

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

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

Table 2.4.19
Reallocation of IP-PF Link Delta (RDS 19)
Worksheet Reallocates IP-PF Link Delta dollars from IP to PF preference and NR loads and recalculates average power rates.

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

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

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

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

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

Table 2.5.6.1
Calculation of Net REP Ratemaking and Recovery Demonstration (DS 06-1)
Worksheet applies all power costs and revenue credits to the PF Public rate pool. The IP revenues are calculated with a macro to arrive at the proper relationship between the PFp rate and the IP rate. The net REP benefits are used in the calculations. The worksheet demonstrates that the PFp rate using the net REP benefits is identical to the PFp calculated with BPA's standard gross REP methodology.

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

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

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

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

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

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

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

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

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

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

Rate Data Input
Disaggregated Loads
Test Period October 2011 - September 2013
(MWh)

	A	B	C	E	F
5				**2012**	**2013**
6	Preference			60,582,273	61,280,658
7			Slice (block)	15,575,833	16,201,276
8			Slice (output energy)	16,988,696	16,625,421
9			Load Following - System Shape	27,922,938	28,247,398
10			Load Following - Load Shaping	-89,298	-288,721
11			Tier 2 (block)	184,104	495,285
12	Industrial			2,990,952	2,982,780
13			Smelter	2,810,880	2,803,200
14			Other Industrial	180,072	179,580
15	New Resource			0	0
16	Firm Power and Services			9,573,706	9,394,067
17			Intraregional Transfer	812,823	807,751
18			WNP3	733,038	728,184
21			Dittmer Station Service	79,785	79,567
28			FBS Obligation	6,163,276	5,995,837
29			Canadian Entitlement	4,588,176	4,420,884
30			USBR Pump Load	1,522,419	1,522,250
31			Hungry Horse	45,653	45,675
39			Locational Exchange	1,933,872	1,926,655
40			Sierra Pacific (Wells)	527,040	525,960
41			PacifiCorp (So Idaho)	1,406,832	1,400,695
50			Seasonal or Capacity Exchange	663,735	663,823
51			Riverside Capacity	42,292	43,282
52			Riverside Seasonal	37,872	37,620
53			Pasadena	13,112	13,112
54			PG&E	227,136	226,982
55			PacifiCorp	50,000	50,000
56			Intertie Losses	9,612	9,630
57			White Creek Shaping	283,710	283,198
61	Presale of Secondary			3,229,053	455,048
62	Conservation			-198,763	-260,319

Rate Data Input
Disaggregated Resources
Test Period October 2011 - September 2013
(MWh)

	A	B	C	E	F
6				**2012**	**2013**
7	Hydro			62,221,298	62,020,245
8		Regulated		57,666,281	57,495,286
9		Independent		3,319,986	3,316,101
10			Cowlitz Falls	230,247	229,919
11			Idaho Falls	123,007	122,752
12			PreAct	2,966,732	2,963,430
20		Hydro Other		1,235,030	1,208,858
21			Canadian Entitlement	1,235,030	1,208,858
22			Other	0	0
31	Non Hydro			9,689,760	8,328,086
32		Water		23,102	23,039
43		Thermal		9,047,520	7,687,488
44			Columbia Generating Station	9,047,520	7,687,488
54		Wind		450,227	449,201
55			Foote Creek 1	44,736	44,565
56			Foote Creek 2	5,259	5,239
57			Foote Creek 4	49,085	48,898
58			Stateline Wind Project	192,264	191,916
59			Condon Wind Project	91,760	91,552
60			Klondike I	67,124	67,032
65		Renewable		168,911	168,358
66			Georgia-Pacific Paper (Wauna)	168,884	168,331
67			Fourmile Hill Geothermal	0	0
68			Ashland Solar Project	27	27
69			White Bluffs Solar	0	0

Rate Data Input
Disaggregated Resources
Test Period October 2011 - September 2013
(MWh)

	A	B	C	E	F
6				**2012**	**2013**
76	Contracts			3,241,954	3,492,659
77		Imports		412,838	405,817
78			Riverside Exchange Energy	64,352	64,350
79			Pasadena Exchange Energy	16,497	16,413
80			BC Hydro Power Purchase	8,784	8,760
81			PacifiCorp Settlement	0	0
82			PacifiCorp Power Purchase	0	0
83			Slice Return of Losses	323,205	316,293
88		Seasonal or Capacity Exchange		701,997	652,108
90			Riverside Seasonal	37,872	37,872
91			Pasadena	13,100	13,083
92			PG&E	224,711	224,664
93			PacifiCorp	100,286	50,000
94			Intertie Losses	0	0
95			White Creek Shaping	283,728	283,198
99		Locational Exchange		1,933,872	1,926,655
100			Sierra Pacific (Wells)	527,040	525,960
101			PacifiCorp (So Idaho)	1,406,832	1,400,695
110		Tier2		193,248	508,080
122	Augmentation			142,069	1,686,121
123		System Augmentation		0	1,544,244
124		Tier 1 Resources		142,069	141,877
125			Klondike III	139,866	139,674
126			Rocky Brook	2,203	2,203

Table 2.1.2.3

Rate Data Input
Disaggregated Resources
Test Period October 2011 - September 2013
(MWh)

	A	B	C	E	F
6				**2012**	**2013**
127					
128	Total FBS			74,157,517	74,391,966
129	Total Exchange			47,454,617	47,599,630
130	Total New Resources			1,137,563	1,135,146
131	Total System (before Augmentation under TRM)			75,295,080	73,982,867
132	Augmented FBS Required for Rate Directive Steps			(230,079)	1,544,181
133					
134	T1SFCO (from LaRIS)			62,672,256	62,501,021
135	Initial CHWM			62,719,701	62,548,336

Table 2.1.3

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2011 - September 2013

	B	D	E
7	**Exchange ASCs ($/MWh)**	**2012**	**2013**
8			
9	Avista	$ 57.46	$ 57.46
10	Idaho Power	$ 46.73	$ 46.73
11	Northwestern	$ 55.35	$ 55.35
12	PacifiCorp	$ 60.18	$ 60.18
13	PGE	$ 68.48	$ 68.48
14	Puget Sound Energy	$ 66.07	$ 66.07
15	Clark	$ 59.44	$ 59.44
17	Snohomish	$ 46.67	$ 46.67
18			
19	**Exchange Loads (GWh)**	**2012**	**2013**
20			
21	Avista	3,906	3,906
22	Idaho Power	5,633	5,633
23	Northwestern	640	640
24	PacifiCorp	9,469	9,469
25	PGE	8,776	8,776
26	Puget Sound Energy	12,044	12,044
27	Clark	2,618	2,645
29	Snohomish	3,637	3,671
30		46,722	46,784
31			
32	**Exchange Resource Cost ($000)**	**2012**	**2013**
33			
34	Avista	$ 224,412	$ 224,412
35	Idaho Power	$ 263,225	$ 263,225
36	Northwestern	$ 35,439	$ 35,439
37	PacifiCorp	$ 569,833	$ 569,833
38	PGE	$ 601,004	$ 601,004
39	Puget Sound Energy	$ 795,756	$ 795,756
40	Clark	$ 155,612	$ 157,234
42	Snohomish	$ 169,715	$ 171,326
43		$ 2,814,996	$ 2,818,228

Energy Allocation Factor
Power Sales and Resources
Test Period October 2011 - September 2013
(aMW)

	B	C	E	F
4			**2012**	**2013**
5	**Sales**			
6	Public			
7		Load Following System Shape	3,179	3,225
8		Load Following Load Shaping	(10)	(33)
9		Tier 2 (block)	21	57
10		Block Service	0	0
11		Slice (output energy)	1,934	1,898
12		Slice (block)	1,773	1,849
13		Undistributted Conservation	(23)	(30)
14	Exports			
15		BC Hydro (Cdn Entitlement)	522	505
16		Pasadena	1.5	1
17		Riverside Capacity	5	5
18		Riverside Seasonal	4	4
19		PG&E	26	26
20		Sierra Pacific (Wells)	60	60
21		Intertie Losses	1	1
22		White Creek	32	32
23	Intra-regional Transfers			
24		PacifiCorp (Capacity/Exchange)	6	6
25		PacifiCorp (Southern Idaho)	160	160
26		Avista (WNP#3 Settle.)	83	83
27		Clark PUD	0	0
28		Puget Sound Energy	0	0
29		Dittmer/Substration Sale	9	9
30	Other Loads			
31		USBR Pump Load	173	174
32		Hungry Horse	5	5
33		Northern Lights	0	0
34		Pre Subscripition	0	0
35		Direct Service Industries	341	341
36		New Resource	0.0	0
37	Total Firm Obligations		**8,304**	**8,378**
38				
39	**Resources**			
40	Hydro			
41		Regulated	6,565	6,563
42		Independent		
43		Cowlitz Falls	26	26
44		Idaho Falls	14	14
45		PreAct	338	338
46		Non-Fed CER (Canada)	141	138
47	Other Hydro Resources		0	0

Table 2.2.1.2

Energy Allocation Factor
Power Sales and Resources
Test Period October 2011 - September 2013
(aMW)

	B	C	E	F
4			**2012**	**2013**
48				
49	Combustion Turbines			
50	Renewables			
51		Foote Creek 1	5	5
52		Foote Creek 2	1	1
53		Foote Creek 4	6	6
54		Stateline Wind Project	22	22
55		Condon Wind Project	10	10
56		Klondike I	8	8
57		Georgia-Pacific Paper (Wauna)	19	19
58		Klondike III	16	16
59		Fourmile Hill Geothermal	0	0
60		Ashland Solar Project	0	0
61		White Bluffs Solar	0	0
62	Cogeneration			
63	Imports			
64		Riverside Exchange Energy	7	7
65		Pasadena Exchange Energy	2	2
66		BC Hydro Power Purchase	1	1
67		Riverside Capacity	5	5
68		Riverside Seasonal	4	4
69		Pasadena	1	1
70		Sierra Pacific (Wells)	60	60
71		PacifiCorp (So Idaho)	160	160
72		Slice Losses Return	37	36
73	Regional Transfers (In)			
74		PacifiCorp Settlement	0	0
75		PacifiCorp Power Purchase	0	0
76		PG&E	26	26
77		PacifiCorp	11	6
78		White Creek	32	32
79	Large Thermal		1,030	878
80	Non-Utility Generation			
81		Dworshak/Clearwater Small Hydropower	3	3
82		Elwha Hydro	0	0
83		Glines Canyon Hydro	0	0
84		Rocky Brook	0	0
85	Augmentation Purchases		0	176
86	Tier 2 Purchases		22	58
87	Federal Trans. Losses		(242)	(243)
88	Total Net Resources		**8,330**	**8,379**

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2011 - September 2013
(aMW)

	B	C	D	E
4			**2012**	**2013**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Slice (block)	1,825	1,903
10		Load Following System Shape	3,271	3,318
11		Load Following Load Shaping	(10)	(34)
12		Slice (output energy)	1,990	1,953
13		Tier 2	21.57	58
14		Undistributted Conservation	(23)	(31)
15		Tier 1 Load Scenario Adjustement	0	0
16		Tier 2 Load Scenario Adjustement	0	0
17		5(c) Exchange	5,473	5,496
18	Industrial Firm - 7(c) Loads			
19		Direct Service Industries	350	350
21	New Resources - 7(f) Loads			
22		NR	0.001	0.001
24	Surplus Firm - SP Loads			
25		Avista (WNP#3 Settle.)	86	86
26		Clark PUD	0	0
27		Dittmer/Substation Sale	9	9
28		Puget Sound Energy	0	0
29		Northern Lights	0	0
30	Total Loads		**12,993**	**13,109**
31				
32	**Resources**			
33	Federal Base System			
34		Hydro	7,043	7,040
35		Other Resources	0	0
36		Small Thermal & Misc.		
37		Combustion Turbines		
38		Renewables	0	0
39		Cogeneration		
40		Imports	241	241
41		Regional Transfers (In)	69	64
42		Large Thermal	1,030	878
43		Non-Utility Generation	0	0
44		Slice Loss Return	37	36
45		Augmentation Purchases	0	176
47		Tier 2 Purchases	22	58

Table 2.2.2.2

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2011 - September 2013
(aMW)

	B	C	D	E
4			**2012**	**2013**
49	less: FBS Obligations			
50		BC Hydro (Cdn Entitlement)	(537)	(519)
51		Hungry Horse	(5)	(5)
52		Pre Subscripition	0	0
53		USBR Pump Load	(178)	(179)
54	less: FBS Uses			
55		Sierra Pacific (Wells)	(62)	(62)
56		PacifiCorp (Southern Idaho)	(165)	(165)
57		PacifiCorp (Capacity/Exchange)	(6)	(6)
58		Pasadena	(2)	(2)
59		Riverside	(9)	(10)
60		PG&E	(27)	(27)
61		Intertie Losses	(1)	(1)
62		White Creek	(32)	(32)
63	Exchange Resources			
64		5(c) Exchange	5,473	5,496
65	New Resources			
66		Cowlitz Falls	26	26
67		Idaho Falls	14	14
68		Foote Creek 1	5	5
69		Foote Creek 2	1	1
70		Foote Creek 4	6	6
71		Stateline Wind Project	22	22
72		Condon Wind Project	10	10
73		Klondike I	8	8
74		Georgia-Pacific Paper (Wauna)	19	19
75		Klondike III	16	16
76		Fourmile Hill Geothermal	0	0
77		Ashland Solar Project	0	0
78		White Bluffs Solar	0	0
79		Dworshak/Clearwater Small Hydropower	3	3
80		Elwha Hydro	0	0
81		Glines Canyon Hydro	0	0
82		Rocky Brook	0	0
83	Total Resources		**13,020**	**13,111**

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2011 - September 2013

	B	C	D
4		**2012**	**2013**
5			
6	**Loads (after adjustments)**		
7	Public	7,074	7,168
8	Exchange	5,473	5,496
9	DSI	350	350
10	NR	0.001	0.001
11	FPS	95	95
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,547	12,664
15	Industrial Firm - 7(c) Loads	350	350
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	95	95
18	Total Firm Loads	12,993	13,109
19	Secondary	2,421	2,216
20	Surplus Firm - SP Loads (for rate protection)	95	95
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,417	7,486
24	Exchange Resources	5,473	5,496
25	New Resources	130	130
26	Total Firm Resources	13,020	13,111
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,417	7,486
31	Industrial Firm - 7(c) Loads	0	0
32	New Resources - 7(f) Loads	0	0
33	Surplus Firm - SP Loads	0	0
34	Exchange Resources		
35	Priority Firm - 7(b) Loads	5,130	5,178
36	Industrial Firm - 7(c) Loads	270	250
37	New Resources - 7(f) Loads	0.0008	0.0007
38	Surplus Firm - SP Loads	73	68
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	80	100
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	22	27

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2011 - September 2013

	B	C	D
4		**2012**	**2013**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9864	0.9832
48	Industrial Firm - 7(c) Loads	0.0107	0.0132
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0029	0.0036
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	0.9372	0.9422
58	Industrial Firm - 7(c) Loads	0.0494	0.0455
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0134	0.0123
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.7863	0.7869
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.2137	0.2131
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9657	0.9660
68	Industrial Firm - 7(c) Loads	0.0270	0.0267
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0073	0.0072
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9728	0.9731
83	Industrial Firm - 7(c) Loads	0.0272	0.0269
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	0.6563	0.6738
91	Industrial Firm - 7(c) Loads	0.0420	0.0430
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3017	0.2833

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2011 - September 2013
($ 000)

	B	F	G
4		2012	2013
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	306,366	345,945
8	Bureau of Reclamation	111,972	119,891
9	Corps of Engineers	208,700	215,700
10	Hydro Insurance	-	-
11	Billing Credits Generation	5,650	5,693
12	Cowlitz Falls O&M	3,123	3,170
13	Idaho Falls Bulb Turbine	4,050	4,523
14	Bureau O&M-Elwha	-	-
15	Clearwater Hatchery Generation	1,028	1,038
16	New Resourcs Integration Wheeling	889	889
17	Wauna	10,340	10,518
18	Other New Resources	-	-
19			
20	**Operating Generation Settlement Payment**		
21	Colville Generation Settlement	21,928	22,148
22	Spokane Generation Settlement	-	-
23			
24	**Non-Operating Generation**		
25	Trojan Decomissioning	1,500	1,500
26	WNP-1&3 Decomissioning	438	448
27			
28	**Contracted and Augmentation Power Purchases**		
29	Augmentation Power Purchases	-	66,155
30	Balancing Purchases	46,827	29,559
31	PNCA Headwater Benefit	2,452	2,704
32	Hedging/Mitigation	43,073	43,073
33	Other Committed Purchases - General (excl. hedging)	1,456	-
34	Bookout Adj to Contracted Power Purchases	-	-
35	Tier 1 Augmentation Resource	10,000	9,997
36			
37	**Exchanges and Settlements**		
38	IOU Residential Exchange Benefits	182,101	182,101
39	COU Residential Exchange Benefits	19,461	19,660
40	Residential Exchange Program Support	1,446	885
41			
42	**Renewable and Conservation Generation**		
43	Renewable Generation R&D	5,622	5,939
44	Contra Expense (for unspent GEP revenues)	(2,625)	(2,625)
45	Renewable Generation Rate Credit	-	-
46	Renewable Generation (excl. Klondike III)	27,670	28,145
47	Generation Conservation R&D	-	-
48	DSM Technology	-	-
49	Conservation Acquisition	15,950	15,950
50	Low Income Weatherization & Tribal	5,000	5,000
51	Energy Efficiency Development	11,500	11,500
52	Legacy Conservation	1,000	900
53	Market Transformation	13,500	14,500
54	Conservation Rate Credit	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2011 - September 2013
($ 000)

	B	F	G
4		**2012**	**2013**
55			
56	**Transmission Acquisition and Ancillary Services**		
57	Transmission & Ancillary Services	61,239	57,324
58	Transmission & Ancillary Services (sys. oblig.)	31,707	31,707
59	Third Party GTA Wheeling	52,263	52,891
60	PS - Third Party Trans & Ancillary Svcs	2,221	2,244
61	Generation Integration	8,865	8,709
62	Wind Integration Team	4,170	4,259
63	Telemetering/Equip Replacement	50	51
64			
65	**Power Non-Generation Operations**		
66	Efficiencies Program	-	-
67	PS - System Operations R&D	-	-
68	Information Technology	7,143	7,316
69	Generation Project Coordination	5,895	5,919
70	Slice Costs Charged to Slice Customer Charge Pool under TRM	-	-
71	Slice Implementation	2,322	2,394
72			
73	**PS Scheduling**		
74	Operations Scheduling	10,041	10,010
75	PS - Scheduling R&D	-	-
76	Operations Planning	6,744	6,709
77			
78	**PS Marketing and Business Support**		
79	Sales & Support	19,745	20,130
80	Strategy, Finance & Risk Mgmt	16,469	17,412
81	Executive and Administrative Services	3,480	3,550
82	Conservation Support	9,555	9,686
83			
84	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
85	Fish & Wildlife	237,394	241,384
86	USF&W Lower Snake Hatcheries	28,800	29,900
87	Planning Council	10,114	10,355
88	Environmental Requirements	302	305
89			
90	**BPA Internal Support**		
91	Additional Post-Retirement Contribution	17,243	17,821
92	Agency Services G&A	39,452	40,359
93	Agency Services G&A (Energy Effic)	12,283	12,303

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2011 - September 2013
($ 000)

	B	F	G
4		**2012**	**2013**
94			
95	**Bad Debt Expense/Other**		
96	Bad Debt Expense (composite)	-	-
97	Bad Debt Expense (non-slice)	-	-
98	Other Income, Expenses, Adjustments (composite)	-	-
99	Other Income, Expenses, Adjustments (non-slice)	-	-
100			
101	**Non-Federal Debt Service**		
102	**Energy Northwest Debt Service**		
103	Columbia Generating Station Debt Service	115,553	100,172
104	WNP-1 Debt Service	282,802	249,288
105	WNP-3 Debt Service	156,299	175,817
106	ENW Retired Debt	-	-
107	ENW LIBOR Interest Rate Swap	-	-
108			
109	**Non-Energy Northwest Debt Service**		
110	Trojan Debt Service	-	-
111	Conservation Debt Service	2,379	2,377
112	Cowlitz Falls Debt Service	11,715	11,709
113	Northern Wasco Debt Service	2,223	2,224
114			
115	**Depreciation and Amortization**		
116	**Depreciation**		
117	Depreciation - BPA	12,391	13,043
118	Depreciation - Corps	85,565	88,285
119	Depreciation - Bureau	24,213	26,232
120			
121	**Amortization**		
122	Amortization - Legacy Conservation	20,948	17,408
123	Amortization - Conservation Acquisitions	28,131	35,636
124	Amortization - CRFM Intangible Investment	6,094	6,094
125	Amortization - Fish & Widlife	25,856	27,629
126			
127			
128	**Interest Expense**		
129	**Net Interest**		
130	Interest On Appropriated Funds	221,866	222,715
131	Capitalization Adjustment	(45,937)	(45,937)
132	Interest On Treasury Bonds	57,681	74,830
133	Amortization of Bond Premiums	185	185
134	AFUDC	(12,511)	(13,592)
135	Interest Earned on BPA Fund for Power (composite)	(11,119)	(17,871)
136	Interest Earned on BPA Fund for Power (non-slice)	(1,362)	1,216

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2011 - September 2013
($ 000)

	B	F	G
4		**2012**	**2013**
137			
138	**Net Interest into Cost Pools**		
139	Net Interest Expense - Hydro	172,194	181,568
140	Net Interest Expense - Fish & Wildlife	17,980	20,095
141	Net Interest Expense - Conservation	17,634	17,220
142	Net Interest Expense - BPA Programs	994	2,663
143			
144	**Net Interest into Cost Pools 7b2**		
145	Net Interest Expense - Hydro 7b2	182,130	191,188
146	Net Interest Expense - Fish & Wildlife 7b2	16,326	16,512
147	Net Interest Expense - BPA Programs 7b2	903	2,188
148			
149	**Net Revenue**		
150	**Minimum Required Net Revenue**		
151	Repayment of Bonds Issued to US Treasury	140,000	122,800
152	Payment of Irrigation Assistance	1,182	58,822
153	Depreciation (MRNR)	(122,169)	(127,560)
154	Amortization (MRNR)	(81,029)	(86,767)
155	Capitalization Adjustment (MRNR)	45,937	45,937
156	Bond Premium Amortization	(185)	(185)
157	Repayment of Federal Construction Appropriations	53,000	-
158	Accrual Revenue (MRNR Adjustment)	3,524	3,524
159	Principal Payment of Fed Debt exceeds non cash expenses	-	-
160			
161	**Minimum Net Revenue into Cost Pools**		
162	MNetRev - Hydro	33,201	13,581
163	MNetRev - Fish & Wildlife	3,467	1,503
164	MNetRev - Conservation	3,400	1,288
165	MNetRev - BPA Programs	192	199
166			
167	**Minimum Net Revenue into Cost Pools 7b2**		
168	MNetRev - Hydro 7b2	81,787	10,929
169	MNetRev - Fish & Wildlife 7b2	7,331	944
170	MNetRev - BPA Programs 7b2	406	125
171			
172	**Planned Net Revenues for Risk into Cost Pools**		
173	PNetRev - Hydro	-	-
174	PNetRev - Fish & Wildlife	-	-
175	PNetRev - Conservation	-	-
176	PNetRev - BPA Programs	-	-
177			
178	**Planned Net Revenues for Risk into Cost Pools 7b2**		
179	PNetRev - Hydro 7b2	-	-
180	PNetRev - Fish & Wildlife 7b2	-	-
181	PNetRev - BPA Programs 7b2	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2011 - September 2013
($ 000)

	B	F	G
4		**2012**	**2013**
182			
183	**Internally Computed Line Items**		
184	Augmentation Power Purchases	-	66,155
185	Balancing Purchases	91,357	72,632
186	Secondary Energy Credit	(447,327)	(459,653)
187	Low Density Discount Costs	31,768	32,944
188	Irrigation Rate Mitigation Costs	19,305	19,305
189	**Charge Credits to Tiered Rate Pools**		
190	Firm Surplus and Secondary Credit (from unused RHWM)	(19,469)	(5,827)
191	Demand Revenue	58,932	61,269
192	Load Shaping Revenue	(16,910)	(11,256)
193	Augmentation RSS & RSC Adder	8,445	23,364
194	Tier 2 Purchase Costs	159	759
195	Tier 2 Rate Design Adjustments	-	-
196	**Tier 2 Other Costs**		
197	**Revenue Credits / Rate Design Adjustments**		
198	Downstream Benefits and Pumping Power	(14,338)	(14,438)
199	Generation Inputs for Ancillary and Other Services Revenue	(127,449)	(131,078)
200	4(h)(10)(c)	(91,062)	(95,847)
201	Colville and Spokane Settlements	(4,600)	(4,600)
202	Green Tags (FBS resources)	-	-
203	Green Tags (New resources)	(2,658)	(2,836)
204	Energy Efficiency Revenues	(11,500)	(11,500)
205	Miscellaneous Credits (incl. GTA)	(3,420)	(3,420)
206	Pre-sub/Hungry Horse	(1,716)	(1,778)
207	PacifiCorp Capacity	-	-
208	Other Locational/Seasonal Exchange	(701)	(701)
209	Upper Baker	(360)	(397)
210	WNP3 Settlement	(29,516)	(29,163)
211	Other Long-Term Contracts	-	-
212	Trading Floor pre-sale of Secondary	(104,592)	(17,176)
213	Network Wind Integration & Shaping	(2,086)	(2,078)
214	Tier 2	-	-
215	Composite Augmentation RSS Revenue Debit/(Credit)	(2,015)	(2,015)
216	Composite Tier 2 RSS Revenue Debit/(Credit)	(43)	(114)
217	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(215)	(645)
218	Composite Non-Federal RSS Revenue Debit/(Credit)	(474)	(482)
219	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(725)	(725)
220	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
221	Non-Slice Tier 2 Rate Design Debit/(Credit)	98	-
222	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	165	165

Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2011 - September 2013
($ 000)

	B	C	D	E
3			**2012**	**2013**
4				
5	**Federal Base System**		**1,953,152**	**2,043,454**
6	Hydro		695,120	706,103
7	Operating Expense	FHYOP	489,724	510,954
8	Net Interest	FHYIT	172,194	181,568
9	PNRR	FHYPR	-	-
10	MRNR	FHYMR	33,201	13,581
11	BPA Fish and Wildlife Program		295,114	301,271
12	Operating Expense	FFWOP	273,667	279,673
13	Net Interest	FFWIT	17,980	20,095
14	PNRR	FFWPR	-	-
15	MRNR	FFWMR	3,467	1,503
16	Trojan	FTR	1,500	1,500
17	WNP #1	FW1	283,240	249,736
18	WNP #2	FCG	421,919	446,117
19	WNP #3	FW3	156,299	175,817
20	System Augmentation	FAU	-	66,155
21	Balancing	FBL	91,357	72,632
22	Tier 2 Costs	2F	8,604	24,123
23				
24	**New Resources**		**74,034**	**75,527**
25	Idaho Falls	NID	4,050	4,523
26	Tier 1 Aug (Klondike III)	NTA	10,000	9,997
27	Cowlitz Falls	NCZ	14,838	14,879
28	Other NR	NOT	45,146	46,128
29				
30	**Residential Exchange**	R	**2,816,442**	**2,819,113**
31				
32	**Conservation**		**146,929**	**149,461**
33	Operating Expense	COP	125,895	130,953
34	Net Interest	CIT	17,634	17,220
35	PNRR	CPR	-	-
36	MRNR	CMR	3,400	1,288
37				
38	**BPA Programs**		**142,110**	**147,525**
39	Operating Expense	BOP	140,924	144,663
40	Net Interest	BIT	994	2,663
41	PNRR	BPR	-	-
42	MRNR	BMR	192	199
43				
44				
45	**Transmission**		**160,516**	**157,185**
46	TBL Transmission/Ancillary Services	TTA	106,031	102,050
47	3Rd Party Trans/Ancillary Services	T3A	2,221	2,244
48	General Transfer Agreements	TGA	52,263	52,891
49				
50	**Total PBL Revenue Requirement**		**5,293,183**	**5,392,264**
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 2011 - September 2013
($ 000)

	B		D		E	F	G	H	I
18	**Program Totals**		**2012**		**2013**				
19	**Low Density Discount Expenses........................**	**$**	**31,768**	**$**	**32,944**				
20	**Irrigation Rate Discount...................................**	**$**	**19,305**	**$**	**19,305**				
21									
22									
23	**TRM Costs after Adjustments**		**2012**		**2013**				
24	**Composite...**	$	2,219,125	$	2,305,710				
25	**Non-Slice...**	$	(299,273)	$	(351,240)				
26	**Slice..**	$	-	$	-				
27	**Tier 2...**	$	8,604	$	24,123				
28	**Total Costs**	$	1,928,457	$	1,978,592				
29									
30	**Low Density Discount**								
31	**Customer Charge LDD**		**2012**		**2013**				
32	**TOCA LDD Offest %.......................................**		1.56%		1.59%				
33									
34									
35	**Irrigation Rate Discount**								
36	**IRD Percentage..**		37.06%						
37	**Total Irrigation Load (MWh)..........................**		1,881,605						
38	**RT1SC...**		7,181						
39	**Irrigation Load Weighted LDD........................**		4.90%						
40									
41			**2012**		**2013**				
42	**Hours...**		8784		8760				
43	**IRD TOCA...**		2.98299%		2.99116%				
44	**Composite Revenue...**	$	69,879,624	$	70,071,014				
45	**Non-Slice Revenue..**	$	(13,915,568)	$	(13,953,681)				
46	**Load Shaping Revenue.....................................**	$	(1,253,303)	$	(1,242,213)				
47	**Total after LDD..**	$	52,029,926	$	52,186,240				
48									
49	**Irrigation Rate Discount...................................**		10.26						
50									
51									

Table 2.3.3.2

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2011 - September 2013
($ 000)

	B	D	E	F	G	H	I
52	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**	**LoadShp Rate**	**Total LDD Discount**	
53	Oct-11	15,332	(3,063)	$ 9.18	$ 37.86	$ 24,800	
54	Oct-11	-	1,032	$ 9.18	$ 31.20	$ 32,184	
55	Nov-11	14,897	(9,086)	$ 9.31	$ 38.37	$ (209,915)	
56	Nov-11	-	(2,051)	$ 9.31	$ 31.40	$ (64,400)	
57	Dec-11	32,446	1,604	$ 9.97	$ 41.10	$ 389,394	
58	Dec-11	-	5,142	$ 9.97	$ 33.39	$ 171,697	
59	Jan-12	22,595	198	$ 9.70	$ 40.03	$ 227,100	
60	Jan-12	-	2,670	$ 9.70	$ 31.70	$ 84,632	
61	Feb-12	17,111	2,274	$ 9.92	$ 40.93	$ 262,826	
62	Feb-12	-	3,067	$ 9.92	$ 33.17	$ 101,731	
63	Mar-12	22,671	1,531	$ 9.60	$ 39.57	$ 278,209	
64	Mar-12	-	538	$ 9.60	$ 32.33	$ 17,382	
65	Apr-12	17,363	8,383	$ 9.10	$ 37.53	$ 472,587	
66	Apr-12	-	5,026	$ 9.10	$ 30.41	$ 152,829	
67	May-12	20,202	(18,631)	$ 8.50	$ 35.06	$ (481,477)	
68	May-12	-	(7,197)	$ 8.50	$ 24.40	$ (175,623)	
69	Jun-12	21,022	(6,121)	$ 8.72	$ 35.97	$ (36,873)	
70	Jun-12	-	(57)	$ 8.72	$ 23.02	$ (1,303)	
71	Jul-12	17,943	(8,391)	$ 10.20	$ 42.07	$ (170,015)	
72	Jul-12	-	7,013	$ 10.20	$ 29.91	$ 209,792	
73	Aug-12	23,820	1,756	$ 10.75	$ 44.35	$ 333,961	
74	Aug-12	-	6,099	$ 10.75	$ 32.15	$ 196,055	
75	Sep-12	15,311	(4,217)	$ 10.53	$ 43.45	$ (22,001)	
76	Sep-12	-	2,123	$ 10.53	$ 33.59	$ 71,332	
77	**Total**					**$ 1,864,902**	
78	Oct-12	19,135	(3,201)	$ 9.18	$ 37.86	$ 54,490	
79	Oct-12	-	568	$ 9.18	$ 31.20	$ 17,733	
80	Nov-12	15,198	(9,865)	$ 9.31	$ 38.37	$ (236,988)	
81	Nov-12	-	(2,506)	$ 9.31	$ 31.40	$ (78,687)	
82	Dec-12	30,821	832	$ 9.97	$ 41.10	$ 341,491	
83	Dec-12	-	5,222	$ 9.97	$ 33.39	$ 174,389	
84	Jan-13	27,436	(136)	$ 9.70	$ 40.03	$ 260,682	
85	Jan-13	-	1,894	$ 9.70	$ 31.70	$ 60,037	
86	Feb-13	17,494	2,920	$ 9.92	$ 40.93	$ 293,031	
87	Feb-13	-	3,323	$ 9.92	$ 33.17	$ 110,214	
88	Mar-13	20,761	710	$ 9.60	$ 39.57	$ 227,391	
89	Mar-13	-	412	$ 9.60	$ 32.33	$ 13,329	
90	Apr-13	21,461	8,457	$ 9.10	$ 37.53	$ 512,653	
91	Apr-13	-	4,620	$ 9.10	$ 30.41	$ 140,486	
92	May-13	21,728	(19,368)	$ 8.50	$ 35.06	$ (494,364)	
93	May-13	-	(7,405)	$ 8.50	$ 24.40	$ (180,698)	
94	Jun-13	18,442	(6,614)	$ 8.72	$ 35.97	$ (77,110)	
95	Jun-13	-	40	$ 8.72	$ 23.02	$ 919	
96	Jul-13	22,972	(8,345)	$ 10.20	$ 42.07	$ (116,784)	
97	Jul-13	-	6,831	$ 10.20	$ 29.91	$ 204,319	
98	Aug-13	25,161	1,692	$ 10.75	$ 44.35	$ 345,527	
99	Aug-13	-	6,170	$ 10.75	$ 32.15	$ 198,342	
100	Sep-13	16,222	(4,369)	$ 10.53	$ 43.45	$ (19,021)	
101	Sep-13	-	1,943	$ 10.53	$ 33.59	$ 65,271	
102	**Total**					**$ 1,816,653**	

Table 2.3.4.1

Cost of Service Analysis
Allocation of Costs
Test Period October 2011 - September 2013
($ 000)

	B		C		D
5	**Costs ($000)**		**2012**		**2013**
6	**FBS..**	$	1,953,152	$	2,043,454
7	**New Resources.....................................**	$	74,034	$	75,527
8	**Residential Exchange..........................**	$	2,816,442	$	2,819,113
9	**Conservation..**	$	146,929	$	149,461
10	**BPAPrograms......................................**	$	142,110	$	147,525
11	**Transmission..**	$	160,516	$	157,185
12	**Irrigation/Low Density Discounts.......**	$	51,073	$	52,249
13	Total...	$	5,344,256	$	5,444,513
14					
15	**Cost Allocation**				
16					
17	**FBS..**	$	1,953,152	$	2,043,454
18					
19	**Federal Base System Allocators..........**		**2012**		**2013**
20	Priority Firm - 7(b) Loads.....................		1.0000		1.0000
21	Industrial Firm - 7(c) Loads..................		0.0000		0.0000
22	New Resources - 7(f) Loads..................		0.0000		0.0000
23	Surplus Firm - SP Loads........................		0.0000		0.0000
24	Total...		1.0000		1.0000
25					
26	**FBS Cost Allocation............................**		**2012**		**2013**
27	Priority Firm - 7(b) Loads.....................	$	1,953,152	$	2,043,454
28	Industrial Firm - 7(c) Loads..................	$	-	$	-
29	New Resources - 7(f) Loads..................	$	-	$	-
30	Surplus Firm - SP Loads........................	$	-	$	-
31	Total...	$	1,953,152	$	2,043,454
32					
33					
34	**Irrigation/Low Density Discounts.......**	$	51,073	$	52,249
35					
36	**Irrigation/LDD Allocators..................**		**2012**		**2013**
37	Priority Firm - 7(b) Loads.....................		1.0000		1.0000
38	Industrial Firm - 7(c) Loads..................		0.0000		0.0000
39	New Resources - 7(f) Loads..................		0.0000		0.0000
40	Surplus Firm - SP Loads........................		0.0000		0.0000
41	Total...		1.0000		1.0000
42					
43	**Irrigation/LDD Cost Allocation.........**		**2012**		**2013**
44	Priority Firm - 7(b) Loads.....................	$	51,073	$	52,249
45	Industrial Firm - 7(c) Loads..................	$	-	$	-
46	New Resources - 7(f) Loads..................	$	-	$	-
47	Surplus Firm - SP Loads........................	$	-	$	-
48	Total...	$	51,073	$	52,249

Cost of Service Analysis
Allocation of Costs
Test Period October 2011 - September 2013
($ 000)

	B	C		D	
5	**Costs ($000)**		**2012**		**2013**
6	**FBS...**	$	1,953,152	$	2,043,454
7	**New Resources.....................................**	$	74,034	$	75,527
8	**Residential Exchange...........................**	$	2,816,442	$	2,819,113
9	**Conservation...**	$	146,929	$	149,461
10	**BPAPrograms.......................................**	$	142,110	$	147,525
11	**Transmission..**	$	160,516	$	157,185
12	**Irrigation/Low Density Discounts.......**	$	51,073	$	52,249
13	Total...	$	5,344,256	$	5,444,513
14					
15	**Cost Allocation (continued)**				
16					
17	**New Resources.....................................**	$	74,034	$	75,527
18					
19	**New Resources Allocators**		**2012**		**2013**
20	Priority Firm - 7(b) Loads.......................		0.0000		0.0000
21	Industrial Firm - 7(c) Loads....................		0.7863		0.7869
22	New Resources - 7(f) Loads...................		0.00000231		0.00000231
23	Surplus Firm - SP Loads.........................		0.2137		0.2131
24	Total...		1.0000		1.0000
25					
26	**New Resources Cost Allocation...........**		**2012**		**2013**
27	Priority Firm - 7(b) Loads.......................	$	-	$	-
28	Industrial Firm - 7(c) Loads....................	$	58,214	$	59,432
29	New Resources - 7(f) Loads...................	$	0.1710	$	0.1745
30	Surplus Firm - SP Loads.........................	$	15,820	$	16,094
31	Total...	$	74,034	$	75,527
32					
33					
34	**Residential Exchange...........................**	$	2,816,442	$	2,819,113
35	Costs Functionalized to Transmission.....	$	(194,833)	$	(195,090)
36	Costs Functionalized to Generation........	$	2,621,610	$	2,624,023
37					
38	**Residential Exchange Allocators**		**2012**		**2013**
39	Priority Firm - 7(b) Loads.......................		0.9372		0.9422
40	Industrial Firm - 7(c) Loads....................		0.0494		0.0455
41	New Resources - 7(f) Loads...................		0.00000014		0.00000013
42	Surplus Firm - SP Loads.........................		0.0134		0.0123
43	Total...		1.0000		1.0000
44					
45	**Residential Exchange Cost Allocation**		**2012**		**2013**
46	Priority Firm - 7(b) Loads.......................	$	2,457,026	$	2,472,362
47	Industrial Firm - 7(c) Loads....................	$	129,414	$	119,343
48	New Resources - 7(f) Loads...................	$	0.380	$	0.350
49	Surplus Firm - SP Loads.........................	$	35,170	$	32,319
50	Total...	$	2,621,610	$	2,624,023

Cost of Service Analysis
Allocation of Costs
Test Period October 2011 - September 2013
($ 000)

	B		C		D
5	**Costs ($000)**		**2012**		**2013**
6	**FBS....**	$	1,953,152	$	2,043,454
7	**New Resources....**	$	74,034	$	75,527
8	**Residential Exchange....**	$	2,816,442	$	2,819,113
9	**Conservation....**	$	146,929	$	149,461
10	**BPAPrograms....**	$	142,110	$	147,525
11	**Transmission....**	$	160,516	$	157,185
12	**Irrigation/Low Density Discounts..**	$	51,073	$	52,249
13	Total....	$	5,344,256	$	5,444,513
14					
15	**Cost Allocation (continued)**				
16					
17	**Conservation....**	$	146,929	$	149,461
18					
19	**BPAPrograms....**	$	142,110	$	147,525
20					
21	**Transmission....**	$	160,516	$	157,185
22					
23					
24	**Conservation & General Allocators**		**2012**		**2013**
25	Priority Firm - 7(b) Loads....		0.9657		0.9660
26	Industrial Firm - 7(c) Loads....		0.0270		0.0267
27	New Resources - 7(f) Loads....		0.0000		0.0000
28	Surplus Firm - SP Loads....		0.0073		0.0072
29	Total....		1.0000		1.0000
30					
31	**Conservation Cost Allocation....**		**2012**		**2013**
32	Priority Firm - 7(b) Loads....	$	141,890	$	144,384
33	Industrial Firm - 7(c) Loads....	$	3,962	$	3,995
34	New Resources - 7(f) Loads....	$	0	$	0
35	Surplus Firm - SP Loads....	$	1,077	$	1,082
36	Total....	$	146,929	$	149,461
37					
38	**BPA Programs Cost Allocation....**		**2012**		**2013**
39	Priority Firm - 7(b) Loads....	$	137,236	$	142,514
40	Industrial Firm - 7(c) Loads....	$	3,832	$	3,943
41	New Resources - 7(f) Loads....	$	0	$	0
42	Surplus Firm - SP Loads....	$	1,041	$	1,068
43	Total....	$	142,110	$	147,525
44					
45	**Transmission Cost Allocation....**		**2012**		**2013**
46	Priority Firm - 7(b) Loads....	$	155,010	$	151,846
47	Industrial Firm - 7(c) Loads....	$	4,329	$	4,201
48	New Resources - 7(f) Loads....	$	0	$	0
49	Surplus Firm - SP Loads....	$	1,176	$	1,138
50	Total....	$	160,516	$	157,185

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2011 - September 2013
($ 000)

	B	C		D	
5	**Costs ($000)**	**2012**		**2013**	
6	**FBS...**	$	1,953,152	$	2,043,454
7	**New Resources.....................................**	$	74,034	$	75,527
8	**Residential Exchange..........................**	$	2,816,442	$	2,819,113
9	**Conservation..**	$	146,929	$	149,461
10	**BPAPrograms.......................................**	$	142,110	$	147,525
11	**Transmission..**	$	160,516	$	157,185
12	**Irrigation/Low Density Discounts.......**	$	51,073	$	52,249
13	Total...	$	5,344,256	$	5,444,513
14					
15	**Cost Allocation (continued)**				
16					
17					
18	**Initial Cost Allocation (Costs /$1000)**	**2012**		**2013**	
19	Priority Firm - 7(b) Loads......................	$	4,895,388	$	5,006,808
20	Industrial Firm - 7(c) Loads...................	$	199,751	$	190,914
21	New Resources - 7(f) Loads..................	$	0.59	$	0.56
22	Surplus Firm - SP Loads........................	$	54,284	$	51,700
23	Total Costs Functionalized to Power......	$	5,149,424	$	5,249,423
24					
25					
26					
27	REP Cost Functionalized to Transmissio	$	194,833	$	195,090
28					
29	Total COSA Revenue Requirement	$	5,344,256	$	5,444,513

Cost of Service Analysis
General Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
5	**General Revenue Credits ($000))**		**2012**		**2013**
6					
7	**FBS**	**$**	**(110,159)**	**$**	**(115,643)**
8	Hydro and Renewable	$	(18,938)	$	(19,038)
9	Downstream Benefits and Pumping Power	$	(14,338)	$	(14,438)
10	Colville and Spokane Settlements	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)	$	-	$	-
12	Fish and Wildlife	$	(91,062)	$	(95,847)
13	4(h)(10)(c)	$	(91,062)	$	(95,847)
14	Tier 2 Adjustment	$	(159)	$	(759)
15	**Contract Obligations**	**$**	**(2,778)**	**$**	**(2,876)**
16	Pre-sub/Hungry Horse	$	(1,716)	$	(1,778)
17	PacifiCorp Capacity	$	-	$	-
18	Other Locational/Seasonal Exchange	$	(701)	$	(701)
19	Upper Baker	$	(360)	$	(397)
20	**New Resources**	**$**	**(2,658)**	**$**	**(2,836)**
21	Green Tags (New resources)	$	(2,658)	$	(2,836)
22	**Conservation**	**$**	**(11,500)**	**$**	**(11,500)**
23	Energy Efficiency Revenues	$	(11,500)	$	(11,500)
24	**BPAPrograms**	**$**	-	**$**	-
25	**Transmission**	**$**	**(3,420)**	**$**	**(3,420)**
26	Miscellaneous Credits (incl. GTA)	$	(3,420)	$	(3,420)
27					
28	**Other Revenue Credits (/$ 000))**		**2012**		**2013**
29	Secondary Revenue	**$**	**(604,727)**	**$**	**(626,339)**
30	Incl. Slice	$	(604,727)	$	(626,339)
31	Generation Inputs for Ancillary and Other Services Revenue	**$**	**(127,449)**	**$**	**(131,078)**
32	Composite Non-Federal RSS Revenue Debit/(Credit)	**$**	**(474)**	**$**	**(482)**
33	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$**	**165**	**$**	**165**
34	Network Wind Integration & Shaping	**$**	**(2,086)**	**$**	**(2,078)**
35	**Contract Revenue from Other Long-term Sales**	**$**	**(29,516)**	**$**	**(29,163)**
36	WNP3 Settlement	$	(29,516)	$	(29,163)
37	Other Long-Term Contracts	$	-	$	-
38					
39	**Total Revenue Credits**	$	(894,601)	$	(925,251)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2012**		**2013**
5	Priority Firm - 7(b) Loads.......................................	$	4,895,388	$	5,006,808
6	Industrial Firm - 7(c) Loads....................................	$	199,751	$	190,914
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	54,284	$	51,700
9	Total...	$	5,149,424	$	5,249,423
10					
11	**General Revenue Credits (/$1000))**		**2012**		**2013**
12					
13	**FBS..**	**$**	**(112,937)**	**$**	**(118,520)**
14	Hydro and Renewable.......................................	$	(18,938)	$	(19,038)
15	Downstream Benefits and Pumping Power..	$	(14,338)	$	(14,438)
16	Colville and Spokane Settlements...............	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources).......................	$	-	$	-
18	Fish and Wildlife...	$	(91,062)	$	(95,847)
19	4(h)(10)(c)..	$	(91,062)	$	(95,847)
20	Tier 2 Adjustment...	$	(159)	$	(759)
21	Contract Obligations...	$	(2,778)	$	(2,876)
22	Pre-sub/Hungry Horse................................	$	(1,716)	$	(1,778)
23	PacifiCorp Capacity...................................	$	-	$	-
24	Other Locational/Seasonal Exchange..........	$	(701)	$	(701)
25	Upper Baker...	$	(360)	$	(397)
26					
27	**Federal Base System Allocators**		**2012**		**2013**
28	Priority Firm - 7(b) Loads.......................................		1.0000		1.0000
29	Industrial Firm - 7(c) Loads....................................		0.0000		0.0000
30	New Resources - 7(f) Loads....................................		0.0000		0.0000
31	Surplus Firm - SP Loads...		0.0000		0.0000
32	Total...		1.0000		1.0000
33					
34	**FBS Credit Allocation**		**2012**		**2013**
35	Priority Firm - 7(b) Loads.......................................	$	(112,937)	$	(118,520)
36	Industrial Firm - 7(c) Loads....................................	$	-	$	-
37	New Resources - 7(f) Loads....................................	$	-	$	-
38	Surplus Firm - SP Loads...	$	-	$	-
39	Total...	$	(112,937)	$	(118,520)
40					
41	**Allocation of Revenue Requirement**		**2012**		**2013**
42	Priority Firm - 7(b) Loads.......................................	$	4,782,451	$	4,888,289
43	Industrial Firm - 7(c) Loads....................................	$	199,751	$	190,914
44	New Resources - 7(f) Loads....................................	$	1	$	1
45	Surplus Firm - SP Loads...	$	54,284	$	51,700
46	Total...	$	5,036,487	$	5,130,904

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
41	**Allocation of Revenue Requirement**		**2012**		**2013**
42	Priority Firm - 7(b) Loads.......................................	$	4,782,451	$	4,888,289
43	Industrial Firm - 7(c) Loads...................................	$	199,751	$	190,914
44	New Resources - 7(f) Loads...................................	$	1	$	1
45	Surplus Firm - SP Loads...	$	54,284	$	51,700
46	Total...	$	5,036,487	$	5,130,904
47					
48					
49	**General Revenue Credits (/$1000))**		**2012**		**2013**
50					
51	**Transmission..**	**$**	**(3,420)**	**$**	**(3,420)**
52	Miscellaneous Credits (incl. GTA)...................	$	(3,420)	$	(3,420)
53					
54	**Conservation & General Cost Allocators**		**2012**		**2013**
55	Priority Firm - 7(b) Loads.......................................		0.9657		0.9660
56	Industrial Firm - 7(c) Loads...................................		0.0270		0.0267
57	New Resources - 7(f) Loads...................................		0.0000		0.0000
58	Surplus Firm - SP Loads...		0.0073		0.0072
59	Total...		1.0000		1.0000
60					
61	**FBS Contract Obligation Revenue Allocation**		**2012**		**2013**
62	Priority Firm - 7(b) Loads.......................................	$	(3,303)	$	(3,304)
63	Industrial Firm - 7(c) Loads...................................	$	(92)	$	(91)
64	New Resources - 7(f) Loads...................................	$	(0)	$	(0)
65	Surplus Firm - SP Loads...	$	(25)	$	(25)
66	Total...	$	(3,420)	$	(3,420)
67					
68	**Allocation of Revenue Requirement**		**2012**		**2013**
69	Priority Firm - 7(b) Loads.......................................	$	4,779,149	$	4,884,985
70	Industrial Firm - 7(c) Loads...................................	$	199,659	$	190,823
71	New Resources - 7(f) Loads...................................	$	1	$	1
72	Surplus Firm - SP Loads...	$	54,259	$	51,676
73	Total...	$	5,033,067	$	5,127,484

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2012**		**2013**
5	Priority Firm - 7(b) Loads...............................	$	4,779,149	$	4,884,985
6	Industrial Firm - 7(c) Loads............................	$	199,659	$	190,823
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads.................................	$	54,259	$	51,676
9	Total...	$	5,033,067	$	5,127,484
10					
11					
12	**General Revenue Credits (/$1000))**		**2012**		**2013**
13					
14	**New Resources...**	**$**	**(2,658)**	**$**	**(2,836)**
15	Green Tags (New resources).....................	$	(2,658)	$	(2,836)
16					
17					
18	**New Resources Cost Allocators**		**2012**		**2013**
19	Priority Firm - 7(b) Loads...............................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads............................		0.7863		0.7869
21	New Resources - 7(f) Loads............................		0.000002		0.000002
22	Surplus Firm - SP Loads.................................		0.2137		0.2131
23	Total...		1.0000		1.0000
24					
25	**New Resources Allocation**		**2012**		**2013**
26	Priority Firm - 7(b) Loads...............................	$	-	$	-
27	Industrial Firm - 7(c) Loads............................	$	(2,090)	$	(2,231)
28	New Resources - 7(f) Loads............................	$	(0.006)	$	(0.007)
29	Surplus Firm - SP Loads.................................	$	(568)	$	(604)
30	Total...	$	(2,658)	$	(2,836)
31					
32	**Allocation of Revenue Requirement**		**2012**		**2013**
33	Priority Firm - 7(b) Loads...............................	$	4,779,149	$	4,884,985
34	Industrial Firm - 7(c) Loads............................	$	197,568	$	188,591
35	New Resources - 7(f) Loads............................	$	0.580	$	0.554
36	Surplus Firm - SP Loads.................................	$	53,691	$	51,071
37	Total...	$	5,030,409	$	5,124,648
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
32	**Allocation of Revenue Requirement**		**2012**		**2013**
33	Priority Firm - 7(b) Loads..............................	$	4,779,149	$	4,884,985
34	Industrial Firm - 7(c) Loads...........................	$	197,568	$	188,591
35	New Resources - 7(f) Loads...........................	$	0.580	$	0.554
36	Surplus Firm - SP Loads................................	$	53,691	$	51,071
37	Total...	$	5,030,409	$	5,124,648
39					
40	**General Revenue Credits (/$1000))**		**2012**		**2013**
41					
42	**Conservation..**	**$**	**(11,500)**	**$**	**(11,500)**
43	Energy Efficiency Revenues.....................	$	(11,500)	$	(11,500)
44					
45					
46	**Conservation & General Cost Allocators**		**2012**		**2013**
47	Priority Firm - 7(b) Loads..............................		0.9657		0.9660
48	Industrial Firm - 7(c) Loads...........................		0.0270		0.0267
49	New Resources - 7(f) Loads...........................		0.0000001		0.0000001
50	Surplus Firm - SP Loads................................		0.0073		0.0072
51	Total...		1.0000		1.0000
52					
53	**Conservation Allocation**		**2012**		**2013**
54	Priority Firm - 7(b) Loads..............................	$	(11,106)	$	(11,109)
55	Industrial Firm - 7(c) Loads...........................	$	(310)	$	(307)
56	New Resources - 7(f) Loads...........................	$	(0.001)	$	(0.001)
57	Surplus Firm - SP Loads................................	$	(84)	$	(83)
58	Total...	$	(11,500)	$	(11,500)
59					
60	**Allocation of Revenue Requirement**		**2012**		**2013**
61	Priority Firm - 7(b) Loads..............................	$	4,768,043	$	4,873,875
62	Industrial Firm - 7(c) Loads...........................	$	197,258	$	188,284
63	New Resources - 7(f) Loads...........................	$	0.579	$	0.553
64	Surplus Firm - SP Loads................................	$	53,607	$	50,988
65	Total...	$	5,018,909	$	5,113,148

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2012**		**2013**
5	Priority Firm - 7(b) Loads..	$	4,768,043	$	4,873,875
6	Industrial Firm - 7(c) Loads..	$	197,258	$	188,284
7	New Resources - 7(f) Loads..	$	0.5793	$	0.5530
8	Surplus Firm - SP Loads...	$	53,607	$	50,988
9	Total..	$	5,018,909	$	5,113,148
10					
11	**General Revenue Credits (/$1000))**		**2012**		**2013**
12					
13	**Generation Inputs...**	**$**	**(127,449)**	**$**	**(131,078)**
14					
15	**Network Wind Integration Shaping Revenues..............**	**$**	**(2,086)**	**$**	**(2,078)**
16					
17	**Credit Due to Idaho Deemer Account...........................**	**$**	**-**	**$**	**-**
19					
20	**Conservation & General Cost Allocators**		**2012**		**2013**
21	Priority Firm - 7(b) Loads..		0.9657		0.9660
22	Industrial Firm - 7(c) Loads..		0.0270		0.0267
23	New Resources - 7(f) Loads..		0.0000001		0.0000001
24	Surplus Firm - SP Loads...		0.0073		0.0072
25	Total..		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2012**		**2013**
28	Priority Firm - 7(b) Loads..	$	(125,092)	$	(128,633)
29	Industrial Firm - 7(c) Loads..	$	(3,493)	$	(3,559)
30	New Resources - 7(f) Loads..	$	(0)	$	(0)
31	Surplus Firm - SP Loads...	$	(949)	$	(964)
32	Total..	$	(129,534)	$	(133,156)
33					
34	**Allocation of Revenue Requirement**		**2012**		**2013**
35	Priority Firm - 7(b) Loads..	$	4,642,951	$	4,745,242
36	Industrial Firm - 7(c) Loads..	$	193,765	$	184,725
37	New Resources - 7(f) Loads..	$	0.5691	$	0.5425
38	Surplus Firm - SP Loads...	$	52,658	$	50,024
39	Total..	$	4,889,374	$	4,979,992
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2011 - September 2013
($ 000)

	B		C		D
34	**Allocation of Revenue Requirement**		**2012**		**2013**
35	Priority Firm - 7(b) Loads..	$	4,642,951	$	4,745,242
36	Industrial Firm - 7(c) Loads...	$	193,765	$	184,725
37	New Resources - 7(f) Loads..	$	0.5691	$	0.5425
38	Surplus Firm - SP Loads..	$	52,658	$	50,024
39	Total...	$	4,889,374	$	4,979,992
41					
42	**Other Revenue Credits**		**2012**		**2013**
43	Composite Non-Federal RSS Revenue Debit/(Credit)..	$	(474)	$	(482)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit)...	$	165	$	165
45					
46					
47	**Conservation & General Cost Allocators**		**2012**		**2013**
48	Priority Firm - 7(b) Loads..		0.9657		0.9660
49	Industrial Firm - 7(c) Loads...		0.0270		0.0267
50	New Resources - 7(f) Loads..		0.0000001		0.0000001
51	Surplus Firm - SP Loads..		0.0073		0.0072
52	Total...		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2012**		**2013**
55	Priority Firm - 7(b) Loads..	$	(299)	$	(306)
56	Industrial Firm - 7(c) Loads...	$	(8)	$	(8)
57	New Resources - 7(f) Loads..	$	(0.0000)	$	(0.0000)
58	Surplus Firm - SP Loads..	$	(2)	$	(2)
59	Total...	$	(309)	$	(317)
60					
61	**Allocation of Revenue Requirement**		**2012**		**2013**
62	Priority Firm - 7(b) Loads..	$	4,642,652	$	4,744,936
63	Industrial Firm - 7(c) Loads...	$	193,757	$	184,716
64	New Resources - 7(f) Loads..	$	0.5690	$	0.5425
65	Surplus Firm - SP Loads..	$	52,655	$	50,022
66	Total...	$	4,889,065	$	4,979,675

Cost of Service Analysis
Calcultaion and Allocation of Secondary Revenue Credit
Test Period October 2011 - September 2013
(aMW, $ 000)

	C		D		E
4	**General Revenue Credits (/$1000))**		**2012**		**2013**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1403.3		1568.8
11					
12	Slice Percentage		26.8539%		26.8539%
13					
14	BPA Secondary Sales Pre-Slice, aMW (row 1 * (1-row 3))		2421.0		2215.8
15					
16	aMW to GWh Multiplier		8.784		8.760
17					
18	BPA Secondary Sales Pre-Slice GWh (row 5 * row 7)		21266.3		19410.6
19					
20	Secondary Sales Price	$	27.56	$	31.98
21	Adhoc Addition to Secondary (includes other commited sales)		107,592.00		20,176.03
22	BPA Secondary Sales Pre-Slice $000 (includes other commited sales)	$	604,727	$	626,339
23					
28	Slice Portion of Secondary	$	157,400	$	166,686
29					
30	**Federal Base System + NR Cost Allocators**		**2012**		**2013**
31	Priority Firm - 7(b) Loads..		0.9864		0.9832
32	Industrial Firm - 7(c) Loads..		0.0107		0.0132
33	New Resources - 7(f) Loads..		0.0000		0.0000
34	Surplus Firm - SP Loads...		0.0029		0.0036
35	Total...		1.0000		1.0000
36					
37					
38	**Allocation of Secondary Revenues Credit**		**2012**		**2013**
39	Priority Firm - 7(b) Loads..	$	(596,525)	$	(615,839)
40	Industrial Firm - 7(c) Loads..	$	(6,449)	$	(8,263)
41	New Resources - 7(f) Loads..	$	(0.0189)	$	(0.0243)
42	Surplus Firm - SP Loads...	$	(1,753)	$	(2,238)
43	Total...	$	(604,727)	$	(626,339)
44					
45	**Allocation of Revenue Requirement**		**2012**		**2013**
46	Priority Firm - 7(b) Loads..	$	4,046,127	$	4,129,097
47	Industrial Firm - 7(c) Loads..	$	187,307	$	176,454
48	New Resources - 7(f) Loads..	$	0.5501	$	0.5182
49	Surplus Firm - SP Loads...	$	50,903	$	47,784
50	Total...	$	4,284,338	$	4,353,336

Cost of Service Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2011 - September 2013
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		**2012**		**2013**
6	Priority Firm - 7(b) Loads..	$	4,046,127	$	4,129,097
7	Industrial Firm - 7(c) Loads...	$	187,307	$	176,454
8	New Resources - 7(f) Loads..	$	0.5501	$	0.5182
9	Surplus Firm - SP Loads..	$	50,903	$	47,784
10	Total..	$	4,284,338	$	4,353,336
11					
12	**Contract Revenue from Other Long-term Sales............**	**$**	**(29,516)**	**$**	**(29,163)**
13	WNP3 Settlement..	$	(29,516)	$	(29,163)
14	Other Long-Term Contracts....................................	$	-	$	-
15					
16	**Calculation of FPS Revenue Deficiency**		**2012**		**2013**
17	Surplus Firm - SP Loads..	$	50,903	$	47,784
18					
19	**Deficiency..**	**$**	**21,387**	**$**	**18,621**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		**2012**		**2013**
24	Priority Firm - 7(b) Loads..		0.9728		0.9731
25	Industrial Firm - 7(c) Loads...		0.0272		0.0269
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**		**2012**		**2013**
31	Priority Firm - 7(b) Loads..	$	20,806	$	18,120
32	Industrial Firm - 7(c) Loads...	$	581	$	501
33	New Resources - 7(f) Loads..	$	0.0017	$	0.0015
34	Surplus Firm - SP Loads..	$	(21,387)	$	(18,621)
35	Total..	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		**2012**		**2013**
39	Priority Firm - 7(b) Loads..	$	4,066,934	$	4,147,217
40	Industrial Firm - 7(c) Loads...	$	187,888	$	176,955
41	New Resources - 7(f) Loads..	$	0.5518	$	0.5197
42	Surplus Firm - SP Loads..	$	29,516	$	29,163
43	Total..	$	4,284,338	$	4,353,336

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2011 - September 2013
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**	**2012**		**2013**	
6	Unbifurcated Priority Firm - 7(b) Loads..	$	4,066,934	$	4,147,217
7	Industrial Firm - 7(c) Loads..	$	187,888	$	176,955
8	New Resources - 7(f) Loads..	$	0.5518	$	0.5197
9	Surplus Firm - SP Loads..	$	29,516	$	29,163
10	Total..	$	4,284,338	$	4,353,336
11					
12					
13	**Energy Billing Determinants (aMW)**	**2012**		**2013**	
14					
15	Unbifurcated Priority Firm - 7(b) Loads..		12,193		12,306
16	Industrial Firm - 7(c) Loads..		341		341
17	New Resources - 7(f) Loads..		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**	**2012**		**2013**	
21					
22	Unbifurcated Priority Firm - 7(b) Loads..		37.97		38.47
23	Industrial Firm - 7(c) Loads..		62.82		59.33
24	New Resources - 7(f) Loads..		62.82		59.33

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2011 - September 2013

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
7			Embedded Cost $/kW/Mo			$ 6.96		
8								
9	1) Assumed DSI sale					341	aMW	
10	Assumed Wheel Turning Load					6	aMW	
11	Interruptible Load					335		
12	percent of DSI sale that is interruptible					10%		
13	MWs of interruptible load					33	MW	
14								
15	Total value of Operating Reserves per year					$ 2,793,744	per year	
16	Value converted to $/MWh on total load					$ 0.94	$/MWh	
17								
18					industrial margin	0.685		
19								
20					**net industrial margin**	**$ (0.255)**		
21								

Table 2.4.2

Rate Directive Step
Calculation of Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2011 - September 2013

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P Q	R	S	T
6	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
7	HLH (mills/kWh)		37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45				
8	LLH (mills/kWh)		31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59				
9	Demand Rate ($/kW/mo)		9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				
10																		
11																		
12	**Unbifurcated PF+NR Load**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2012**	
13	**2012**	HLH	4875	5519	6272	6149	5329	5342	4493	5369	5143	5552	5327	4788			Energy (GWH)	107106
14		LLH	3160	3883	4303	4369	3603	3553	3119	3586	3204	3592	3253	3323			Allocated Cost	$ 4,144,076
15		Demand	718	691	1597	1055	923	1080	775	787	896	727	977	604			Rate Scalar	**1.62**
16	Revenue at marginal Rates		$ 289,756	$ 340,112	$ 417,368	$ 394,863	$ 346,786	$ 336,637	$ 270,517	$ 282,419	$ 266,548	$ 348,419	$ 351,349	$ 326,034		$ 3,970,810		
17			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2013**	
18	**2013**	HLH	4990	5586	6203	6212	5311	5349	4606	5221	4956	5657	5396	4858			Energy (GWH)	107805
19		LLH	3153	3936	4510	4433	3607	3678	3106	3592	3131	3602	3325	3387			Allocated Cost	$ 4,212,678
20		Demand	894	724	1396	1306	864	915	980	815	732	951	1008	627			Rate Scalar	**1.96**
21	Revenue at marginal Rates		$ 295,526	$ 344,624	$ 419,435	$ 401,849	$ 345,593	$ 339,380	$ 276,228	$ 277,616	$ 256,733	$ 355,426	$ 357,013	$ 331,479		$ 4,000,901		
42																		
43																		
49																		
50																		
51	**IP Load**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2012**	
52	**2012**	HLH	142	136	142	136	136	147	136	142	142	136	147	131			Energy (GWH)	2991
53		LLH	112	109	112	117	101	106	109	112	104	117	106	114			Allocated Cost	$ 110,747
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**1.36**
55	Revenue at marginal Rates		$ 8,847	$ 8,658	$ 9,550	$ 9,165	$ 8,918	$ 9,245	$ 8,425	$ 7,691	$ 7,478	$ 9,234	$ 9,939	$ 9,525		$ 106,674		
56			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2013**	
57	**2013**	HLH	147	136	136	142	131	142	142	142	136	142	147	131			Energy (GWH)	2983
58		LLH	106	109	117	112	98	111	104	112	109	112	106	114			Allocated Cost	$ 111,494
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**1.71**
60	Revenue at marginal Rates		$ 8,884	$ 8,658	$ 9,508	$ 9,210	$ 8,604	$ 9,205	$ 8,463	$ 7,691	$ 7,407	$ 9,300	$ 9,939	$ 9,525		$ 106,395		

Rate Directive Step
Calculation of Monthly Energy Rates to be Used in First IP-PF Link Calculation
Test Period October 2011 - September 2013
($/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
6	HLH (mills/kWh)		37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45				
7	LLH (mills/kWh)		31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59				
8	Demand Rate ($/kW/mo)		9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				
9																		
10																		
11	**Unbifurcated PF/NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2012**	HLH	39.48	39.99	42.71	41.64	42.55	41.19	39.15	36.68	37.59	43.69	45.97	45.07				**2012**
13		LLH	32.82	33.02	35.01	33.32	34.79	33.95	32.03	26.02	24.64	31.53	33.77	35.21				**1.62**
14		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2013**	HLH	39.82	40.33	43.06	41.99	42.89	41.54	39.49	37.02	37.93	44.04	46.32	45.42				**2013**
17		LLH	33.16	33.36	35.35	33.66	35.13	34.29	32.37	26.36	24.98	31.87	34.11	35.55				**1.96**
18		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
35																		
36																		
41																		
42																		
43		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
44	**2012**	HLH	39.22	39.73	42.46	41.39	42.29	40.94	38.89	36.42	37.33	43.44	45.71	44.82				**2010**
45		LLH	32.56	32.76	34.75	33.06	34.53	33.69	31.77	25.76	24.38	31.27	33.51	34.95				**1.36**
46		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
47			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
48	**2013**	HLH	39.57	40.08	42.81	41.74	42.64	41.28	39.24	36.77	37.68	43.78	46.06	45.16				**2011**
49		LLH	32.91	33.11	35.10	33.41	34.88	34.04	32.12	26.11	24.73	31.62	33.86	35.30				**1.71**
50		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2011 - September 2013
($ 000)

	B	C	D	E	F	G	H
4						**FY 2012**	**FY 2013**
5							
6		1	IP Allocated Costs			187,888	176,955
7		2	IP Revenues @ Net Margin			(764)	(762)
8		3	adjustment			182	229
9		4	IP Marginal Cost Rate Revenues			106,674	106,395
10		5	PF/NR Marginal Cost Rate Revenues			3,970,810	4,000,901
11		6	PF/NR Allocated Energy Costs			4,066,934	4,147,217
12		7	Numerator: 1-2-3-((4/5)*6)			79,214	67,202
13		8					
14		9	PF Allocation Factor for Delta			0.999999918	0.999999919
15		10	NR Allocation Factor for Delta			0.000000082	0.000000081
16		11	Total Allocation Factors for Delta			1.000000000	1.000000000
17		12	Denominator: 1.0 + ((9/11)*(4/5))			1.0269	1.0266
18		13					
19		14	DELTA: (7/12)			**77,142**	**65,461**
20							
21						-0.256	-0.255
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2011 - September 2013
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement)**		**2012**		**2013**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,066,934	$	4,147,217
7	Industrial Firm - 7(c) Loads..	$	187,888	$	176,955
8	New Resources - 7(f) Loads...	$	0.5518	$	0.5197
9	Surplus Firm - SP Loads..	$	29,516	$	29,163
10	Total..	$	4,284,338	$	4,353,336
11					
12					
13	**First IP-PF Link Delta**	**$**	**77,142**	**$**	**65,461**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2012**		**2013**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999918		0.999999919
18	Industrial Firm - 7(c) Loads..		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads...		0.000000082		0.000000081
20					
21	**7(c)(2) Delta Cost Allocation**		**2012**		**2013**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	77,142	$	65,461
23	Industrial Firm - 7(c) Loads..	$	(77,142)	$	(65,461)
24	New Resources - 7(f) Loads...	$	0.006	$	0.005
25	Total..	$	0	$	(0)
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2012**		**2013**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,144,075	$	4,212,677
29	Industrial Firm - 7(c) Loads..	$	110,747	$	111,494
30	New Resources - 7(f) Loads...	$	0.558	$	0.525
31	Surplus Firm - SP Loads..	$	29,516	$	29,163
32	Total..	$	4,284,338	$	4,353,336
33					
34	**Energy Billing Determinants (aMW)**		**2012**		**2013**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		12,193		12,306
36	Industrial Firm - 7(c) Loads..		340.5		340.5
37	New Resources - 7(f) Loads...		0.001		0.001
38					
39					
40	**Average Power Rates ($/MWh)**		**2012**		**2013**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		38.69		39.08
43	Industrial Firm - 7(c) Loads..		37.03		37.38
44	New Resources - 7(f) Loads...		63.54		59.93
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**38.88**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2011 - September 2013

	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]		3,405	4,767	3,473	2,501	8,172	5,974
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		15,731	10,535	51,055	30,508	59,982	167,811
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]		28.09					
36	20	Floor Rate (mills/kWh)[8]		20.96					
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
DSI Floor Rate Test
Test Period October 2011 - September 2017

	B	C	D	E	F	G	H	I
8								
9								
10								
11		Industrial Firm Power Floor Rate Test						
12						**A**	**B**	**C**
13								
14								
15						**Total**		**Average**
16						**Energy**	**TOTALS**	**Rate**
17								
18								
19	1	IP Billing Determinants				5,974		
20	2	Floor Rate (mills/kWh)				20.96		
21	3	Value of Reserves Credit (mills/kWh)						
22	4	Revenue at Floor Rate Less VOR Credit				125,232	125,232	20.96
23	5	IP Revenue Under Proposed Rates					222,241	37.20
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 2011 - September 2013

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2012**	**2013**	Total
10		Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,144,075	$ 4,212,677	$ 8,356,753
11					
12		**Energy Billing Determinants (aMW)**	**2012**	**2013**	
13		Unbifurcated Priority Firm - 7(b) Loads..............................	12,193	12,306	
14					
15					
16		**Average Power Rates**	**2012**	**2013**	
17					
18		Unbifurcated Priority Firm - 7(b) Loads..............................	38.69	39.08	
25					
26			(GWh)		
27		Two Year PF Public Load T1	120724		
28		Two Year PF Public Load T2	679		
29		Two Year IOU PF Exchange Load	80936		
30		Two Year COU PF Exchange Load	12571		
31		Total Two-Year Unbifurcated PF Load	214911		
32					
33					
34		T 2 Costs	$ 32,727		
35		T 1 Costs	$ 8,324,026		
36		Total	$ 8,356,753		
37					
45		Total PF Costs Minus PF T2 Costs	$ 8,324,026		
46		Total PF Load Minus PF T2 Load	214,231		
47		COU Base PF w/o Transmission	38.86		
48		Exchange Transmission Adder	4.17		
49		**COU Base PFx**	**43.03**		
50					
51					
52		Two Year COU PF Exchange Load	12571		
53		Two Year Base PF Public Exchange T2 Revenue	$ 488,440		
54					
55		Total PF Costs Minus COU PFx Revenue	$ 7,868,313		
56		Total PF Loads Minus COU PFx Loads	202,340		
57		IOU Base PF w/o Transmission	38.89		
58		Exchange Transmission Adder	4.17		
59		**IOU Base PFx**	**43.06**		
60					

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2011 - September 2013

	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 amount of withheld REP benefits (Refund Amounts	$76,538	
16			
17			
18	IOU Scheduled Amount	$182,100	
19	Refund Amount	$76,538	
20	REP Recovery Amount	$258,638	
21			
26			
27			
28		**2012**	**2013**
29		($000)	($000)
30	IOU Unconstrained Benefits	$ 747,254	$ 747,254
31	REP Recovery Amount	**$ 258,638**	**$ 258,638**
32	Rate Protection Delta	$ 488,616	$ 488,616
33			

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2011 - September 2013

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**43.06**									
6	**COU Base PFx**	**43.03**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2012**	**2013**		**2012**	**2013**		**2012**	**2013**
9											
10											
11	Avista	1		57.46	57.46		3,906	3,906		$ 56,253	$ 56,253
12	Idaho Power	1		46.73	46.73		5,633	5,633		$ 20,692	$ 20,692
13	Northwestern	1		55.35	55.35		640	640		$ 7,871	$ 7,871
14	PacifiCorp	1		60.18	60.18		9,469	9,469		$ 162,138	$ 162,138
15	PGE	1		68.48	68.48		8,776	8,776		$ 223,124	$ 223,124
16	Puget Sound Energy	1		66.07	66.07		12,044	12,044		$ 277,176	$ 277,176
17	Clark	1		59.44	59.44		2,618	2,645		$ 42,973	$ 43,421
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish	1		46.67	46.67		3,637	3,671		$ 13,254	$ 13,380
20	Utility #3	0		0.00	0.00		0	0		$ -	$ -
21	Utility #4	0		0.00	0.00		0	0		$ -	$ -
22	Utility #5	0		0.00	0.00		0	0		$ -	$ -
23	Utility #6	0		0.00	0.00		0	0		$ -	$ -
24	Utility #7	0		0.00	0.00		0	0		$ -	$ -
25	Utility #8	0		0.00	0.00		0	0		$ -	$ -
26	Utility #9	0		0.00	0.00		0	0		$ -	$ -
27	Utility #10	0		0.00	0.00		0	0		$ -	$ -
28	Utility #11	0		0.00	0.00		0	0		$ -	$ -
29	Utility #12	0		0.00	0.00		0	0		$ -	$ -
30	Utility #13	0		0.00	0.00		0	0		$ -	$ -
31	Total									**$ 803,481**	**$ 804,054**
32											
33									IOU	**$ 747,254**	**$ 747,254**

Rate Directive Step
Calculation of Settlement Utility-Specific PF Exchange Rates
Test Period October 2011 - September 2013

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY2012**	**FY2013**	**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	1	57.46	43.06	3,906	3,906	3,906	$ 56,253			$ 36,783	$ 5,762	10.89	53.95	$ 13,708
9	Idaho Power	1	46.73	43.06	5,633	5,633	5,633	$ 20,692			$ 13,530	$ 2,119	2.78	45.83	$ 5,042
10	Northwestern	1	55.35	43.06	640	640	640	$ 7,871			$ 5,147	$ 806	9.30	52.35	$ 1,918
11	PacifiCorp	1	60.18	43.06	9,469	9,469	9,469	$ 162,138			$ 106,019	$ 16,607	12.95	56.01	$ 39,512
12	PGE	1	68.48	43.06	8,776	8,776	8,776	$ 223,124			$ 145,897	$ 22,854	19.23	62.28	$ 54,374
13	Puget Sound	1	66.07	43.06	12,044	12,044	12,044	$ 277,176			$ 181,241	$ 28,390	17.41	60.46	$ 67,546
14	Clark	1	59.44	43.03	2,618	2,645	2,632	$ 43,197			$ 28,246		10.73	53.76	$ 14,951
15	Franklin	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish	1	46.67	43.03	3,637	3,671	3,654	$ 13,317			$ 8,708		2.38	45.41	$ 4,609
17	Total							$ 803,768	$182,100	$76,538	$ 525,570	$76,538			$ 201,660
18															
19	rounding to 3 places = $710						IOU Σ(g)	$ 747,254	$182,100	$258,638	$ 488,616	IOU Σ(j)		IOU REP	$ 182,100
20							COU Σ(g)	$ 56,514		$19,560	$ 36,953	COU Σ(j)		COU REP	$ 19,560

	B	D	E	F	G	H	I	J	L	N	O	P
21												
22	**IOU Reallocations**											
23		**Interim**				**Final**	**Final**	**Final**	**Final**		**FY2012**	**FY2013**
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=g-q	s=r/e	t=c+s	u=(a-t)*e		v=(a-t)*c	w=(a-t)*d
27	Avista	$ 13,708	$ 2,005	$ 135	$ 11,839	$ 44,414	11.37	54.4290	$ 11,838	Avista	$ 11,838	$ 11,838
28	Idaho Power	$ 5,042	$ 2,521	$ -	$ 2,521	$ 18,170	3.23	46.2820	$ 2,524	Idaho Power	$ 2,524	$ 2,524
29	Northwestern	$ 1,918	$ (766)	$ 223	$ 2,907	$ 4,964	7.75	50.8090	$ 2,907	Northwestern	$ 2,907	$ 2,907
30	PacifiCorp	$ 39,512	$ 8,443	$ 390	$ 31,459	$ 130,679	13.80	56.8580	$ 31,455	PacifiCorp	$ 31,455	$ 31,455
31	PGE	$ 54,374	$ 1,238	$ 5,124	$ 58,260	$ 164,865	18.79	61.8420	$ 58,257	PGE	$ 58,257	$ 58,257
32	Puget Sound	$ 67,546	$ -	$ 7,568	$ 75,114	$ 202,062	16.78	59.8330	$ 75,119	Puget Sound	$ 75,119	$ 75,119
33	Total	$ 182,100	$ 13,440	$ 13,440	$ 182,100	$ 565,154			$ 182,101	IOU REP	$ 182,101	$ 182,101
34												
35										Clark	$ 14,874	$ 15,029
36										Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**									Snohomish	$ 4,587	$ 4,631
38		Avista	Idaho Power	Northwestern	PacifiCorp	PGE	Puget Sound	Total		COU REP	$ 19,461	$ 19,660
39		$ 2,005	$ 2,521	$ (766)	$ 8,443	$ 1,238	$ -			Total REP	$ 201,562	$ 201,760
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		$ 195	$ (60)				$ 135		Refund Amt	$ 76,538	$ 76,538
42	Idaho Power							$ -		REP Cost	$ 278,099	$ 278,298
43	Northwestern	$ 31	$ 27		$ 131	$ 34	$ -	$ 223				
44	PacifiCorp		$ 563	$ (173)				$ 390				
45	PGE	$ 880	$ 774	$ (238)	$ 3,707			$ 5,124				
46	Puget Sound	$ 1,093	$ 962	$ (295)	$ 4,605	$ 1,203		$ 7,568				
47		$ 2,005	$ 2,521	$ (766)	$ 8,443	$ 1,238	$ -	$ 13,440				

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2011 - September 2013

	B	C		D	
4	**Cost Allocation After 7c2 Delta**		**2012**		**2013**
5	Priority Firm Public - 7(b) Loads..	$	2,336,320	$	2,384,491
6	Priority Firm Exchange - 7(b) Loads....................................	$	1,807,755	$	1,828,187
7	Industrial Firm - 7(c) Loads..	$	110,747	$	111,494
8	New Resources - 7(f) Loads..	$	0.558	$	0.525
9	Surplus Firm - SP Loads..	$	29,516	$	29,163
10	Total..	$	4,284,338	$	4,353,336
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2012**		**2013**
14	Unconstrained Benefits	$	803,481	$	804,054
15	REP Recovery Amount plus COU Benefits	$	(278,099)	$	(278,298)
16	delta	$	525,381	$	525,756
17					
18					
19	**Allocation Factors**		**2012**		**2013**
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**		**2012**		**2013**
27	Priority Firm Public - 7(b) Loads..	$	(525,381)	$	(525,756)
28	Priority Firm Exchange - 7(b) Loads....................................	$	525,381	$	525,756
29	Industrial Firm - 7(c) Loads..	$	-	$	-
30	New Resources - 7(f) Loads..	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2012**		**2013**
35	Priority Firm Public - 7(b) Loads..	$	1,810,939	$	1,858,734
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,333,137	$	2,353,943
37	Industrial Firm - 7(c) Loads..	$	110,747	$	111,494
38	New Resources - 7(f) Loads..	$	0.558	$	0.525
39	Surplus Firm - SP Loads..	$	29,516	$	29,163
40	Total..	$	4,284,338	$	4,353,336
41					
42					
43	**Energy Billing Determinants (aMW)**		**2012**		**2013**
44	Priority Firm Public - 7(b) Loads..		6,874		6,966
45	Priority Firm Exchange - 7(b) Loads....................................		5,319		5,341
46	Industrial Firm - 7(c) Loads..		341		341
47	New Resources - 7(f) Loads..		0.001		0.001
48					
50					
51	**Average Power Rates**		**2012**		**2013**
52	Priority Firm Public - 7(b) Loads..		29.99		30.46
53	Priority Firm Exchange - 7(b) Loads....................................		54.11		54.49
54	Industrial Firm - 7(c) Loads..		37.03		37.38
55	New Resources - 7(f) Loads..		63.54		59.93

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2011 - September 2013

	B	C		D	
25			2012		2013
26	WP-10 Average IOU REP Benefits (before Lookback recovery	$	265,847	$	265,847
27					
28		$	7.38	$	7.38
29	IP/NR REP Surcharge	$	7.72	$	7.73
30	IP Load		2,991		2,983
31	NR Load		0		0
32	REP Surharge Revenue from IP Rate	$	23,091	$	23,044
33	REP Surharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP benefits not covered through IP/NR Surcharge	$	255,009	$	255,254
36	Base REP Share in PF, IP and NR Rates ($/MWh)	$	4.02	$	3.99
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	35,126	$	34,940
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	22,001	$	21,970
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	**Reallocation that Should be in Rates**		**2012**		**2013**
48	Priority Firm Public - 7(b) Loads...	$	242,974	$	243,358
49	Industrial Firm - 7(c) Loads...	$	35,126	$	34,940
50	New Resources - 7(f) Loads..	$	0.103	$	0.103
51		$	278,099	$	278,298
52					
53	**Adjustment Necessary to Achieve Reallocation**		**2012**		**2013**
54	Priority Firm Public - 7(b) Loads...	$	(22,001)	$	(21,970)
55	Industrial Firm - 7(c) Loads...	$	22,001	$	21,970
56	New Resources - 7(f) Loads..	$	0.065	$	0.065
57		$	(0)	$	0
58					
59			**2012**		**2013**
60	PF Contribution to Net REP Benefits $/MWh.........................		4.02		3.99
61	IP Contribution to Net REP Benefits $/MWh..........................		11.74		11.71
62	NR Contribution to Net REP Benefits $/MWh........................		11.74		11.71

Rate Directive Step
Allocate Rate Protection Provided by the IP and NR Rates
Test Period October 2011 - September 2013

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2012**		**2013**
5	Priority Firm Public - 7(b) Loads	$	1,810,939	$	1,858,734
6	Priority Firm Exchange - 7(b) Loads	$	2,333,137	$	2,353,943
7	Industrial Firm - 7(c) Loads	$	110,747	$	111,494
8	New Resources - 7(f) Loads	$	0.558	$	0.525
9	Surplus Firm - SP Loads	$	29,516	$	29,163
10	Total	$	4,284,338	$	4,353,336
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2012**		**2013**
15	Priority Firm Public - 7(b) Loads	$	(22,001)	$	(21,970)
16					
17	Industrial Firm - 7(c) Loads	$	22,001	$	21,970
18	New Resources - 7(f) Loads	$	0.065	$	0.065
19	Total	$	(0)	$	0
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2012**		**2013**
23	Priority Firm Public - 7(b) Loads	$	1,788,938	$	1,836,764
24	Priority Firm Exchange - 7(b) Loads	$	2,333,137	$	2,353,943
25	Industrial Firm - 7(c) Loads	$	132,748	$	133,464
26	New Resources - 7(f) Loads	$	0.623	$	0.590
27	Surplus Firm - SP Loads	$	29,516	$	29,163
28	Total	$	4,284,338	$	4,353,336
29					
30					
31	**Energy Billing Determinants (aMW)**		**2012**		**2013**
32	Priority Firm Public - 7(b) Loads		6,874		6,966
33	Priority Firm Exchange - 7(b) Loads		5,319		5,341
34	Industrial Firm - 7(c) Loads		341		341
35	New Resources - 7(f) Loads		0.001		0.001
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2012**		**2013**
40	Priority Firm Public - 7(b) Loads		29.63		30.10
41	Priority Firm Exchange - 7(b) Loads		54.11		54.49
42	Industrial Firm - 7(c) Loads		44.38		44.75
43	New Resources - 7(f) Loads		70.90		67.30

Rate Directive Step
Calculation of Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2011 - September 2013

	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)		37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45					
8	LLH (mills/kWh)		31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59					
9	Demand Rate ($/kW/mo)		9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53					
10																			
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2012**	
12	**2012**	HLH	2748	3111	3536	3467	3005	3012	2533	3027	2899	3130	3003	2699				Energy (GWH)	60384
13		LLH	1782	2189	2426	2463	2031	2003	1758	2022	1806	2025	1834	1874				Allocated Cost	$ 1,813,733
14		Demand	405	390	900	595	520	609	437	444	505	410	551	341				Rate Scalar	**-7.04**
15		Revenue at marginal Rates	$ 163,357	$ 191,746	$ 235,301	$ 222,614	$ 195,509	$ 189,787	$ 152,511	$ 159,221	$ 150,273	$ 196,429	$ 198,081	$ 183,809			$ 2,238,638		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2013**	
17	**2013**	HLH	2825	3162	3511	3516	3006	3028	2607	2955	2805	3202	3054	2750				Energy (GWH)	61020
18		LLH	1785	2228	2553	2509	2042	2082	1758	2033	1772	2039	1882	1917				Allocated Cost	$ 1,861,269
19		Demand	506	410	790	739	489	518	555	461	414	538	570	355				Rate Scalar	**-6.61**
20		Revenue at marginal Rates	$ 167,276	$ 195,067	$ 237,412	$ 227,457	$ 195,615	$ 192,098	$ 156,353	$ 157,138	$ 145,318	$ 201,181	$ 202,079	$ 187,626			$ 2,264,620		
21																			
22																			
23																			
24																			
25		**IP Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2012**	
26	**2012**	HLH	142	136	142	136	136	147	136	142	142	136	147	131				Energy (GWH)	2991
27		LLH	112	109	112	117	101	106	109	112	104	117	106	114				Allocated Cost	$ 107,953
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**0.43**
29		Revenue at marginal Rates	$ 8,847	$ 8,658	$ 9,550	$ 9,165	$ 8,918	$ 9,245	$ 8,425	$ 7,691	$ 7,478	$ 9,234	$ 9,939	$ 9,525			$ 106,674		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2013**	
31	**2013**	HLH	147	136	136	142	131	142	142	142	136	142	147	131				Energy (GWH)	2983
32		LLH	106	109	117	112	98	111	104	112	109	112	106	114				Allocated Cost	$ 108,960
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**0.86**
34		Revenue at marginal Rates	$ 8,884	$ 8,658	$ 9,508	$ 9,210	$ 8,604	$ 9,205	$ 8,463	$ 7,691	$ 7,407	$ 9,300	$ 9,939	$ 9,525			$ 106,395		
35																			

Rate Directive Step
Calculation of Monthly Energy Rates to be Used in Second IP-PF Link Calculation
Test Period October 2011 - Septmenber 2013

	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)		37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45				
7	LLH (mills/kWh)		31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59				
8	Demand Rate ($/kW/mo)		9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				
9																		
10																		
11	**Unbifurcated PF /NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2012**	HLH	30.82	31.33	34.06	32.99	33.89	32.54	30.49	28.02	28.93	35.04	37.31	36.42				**2012**
13		LLH	24.16	24.36	26.35	24.66	26.13	25.29	23.37	17.36	15.98	22.87	25.11	26.55				**-7.04**
14		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2013**	HLH	31.25	31.76	34.49	33.42	34.32	32.96	30.92	28.45	29.36	35.46	37.74	36.84				**2013**
17		LLH	24.59	24.79	26.78	25.09	26.56	25.72	23.80	17.79	16.41	23.30	25.54	26.98				**-6.61**
18		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2012**	HLH	38.29	38.80	41.52	40.45	41.36	40.00	37.96	35.49	36.40	42.50	44.78	43.88				**2010**
23		LLH	31.63	31.83	33.82	32.13	33.60	32.76	30.84	24.83	23.45	30.34	32.58	34.02				**0.43**
24		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2013**	HLH	38.72	39.23	41.96	40.89	41.79	40.43	38.39	35.92	36.83	42.93	45.21	44.31				**2011**
27		LLH	32.06	32.26	34.25	32.56	34.03	33.19	31.27	25.26	23.88	30.77	33.01	34.45				**0.86**
28		Demand	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53				**Scalar**

Table 2.4.18

Rate Directive Step
Calculation of IP-PF Link
Test Period October 2011 - September 2013

	B	C	D	E	F	G	H	I
4						**FY 2012**	**FY 2013**	
5								
6	1	IP Allocated Costs				110,747	111,494	
7	2	IP Revenues @ Net Margin				(764)	(762)	
8	3	adjustment				290	307	
9	4	IP Marginal Cost Rate Revenues				106,674	106,395	
10	5	PF/NR Marginal Cost Rate Revenues				2,238,638	2,264,620	
11	6	PF Allocated Energy Costs				1,788,938	1,836,765	
12	7	Numerator: 1-2-3-((4/5)*6)				25,976	25,655	
13	8							
14	9	PF Allocation Factor for Delta				0.999999918	0.999999919	
15	10	NR Allocation Factor for Delta				0.000000082	0.000000081	
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000	
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0477	1.0470	
18	13							
19	14	DELTA: (7/12)				**24,795**	**24,504**	
20								
21						-0.256	-0.256	
22								

Rate Directive Step
Allocation of Settlement IP-PF Link Delta and Calculation of Rates
Test Period October 2011 - September 2013

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2012**	**2013**	
5	Priority Firm Public - 7(b) Loads	$ 1,788,938	$ 1,836,764	
6	Priority Firm Exchange - 7(b) Loads	$ 2,333,137	$ 2,353,943	
7	Industrial Firm - 7(c) Loads	$ 132,748	$ 133,464	
8	New Resources - 7(f) Loads	$ 0.623	$ 0.590	
9	Surplus Firm - SP Loads	$ 29,516	$ 29,163	
10	Total	$ 4,284,338	$ 4,353,336	
11				
12				
13	IP-PF Link Delta	$ 24,795	$ 24,504	
14				
15		**2012**	**2013**	
16	Priority Firm Public - 7(b) Loads	0.99999985	0.99999986	
17	Industrial Firm - 7(c) Loads	(1.00000000)	(1.00000000)	
18	New Resources - 7(f) Loads	0.00000015	0.00000014	
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2012**	**2013**	
22	Priority Firm Public - 7(b) Loads	$ 24,795	$ 24,504	
23	Priority Firm Exchange - 7(b) Loads	$ -	$ -	
24	Industrial Firm - 7(c) Loads	$ (24,795)	$ (24,504)	
25	New Resources - 7(f) Loads	$ 0.004	$ 0.004	
26	Total	$ (0)	$ (0)	
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2012**	**2013**	
30	Priority Firm Public - 7(b) Loads	$ 1,813,732	$ 1,861,268	
31	Priority Firm Exchange - 7(b) Loads	$ 2,333,137	$ 2,353,943	
32	Industrial Firm - 7(c) Loads	$ 107,953	$ 108,960	
33	New Resources - 7(f) Loads	$ 0.626	$ 0.593	
34	Surplus Firm - SP Loads	$ 29,516	$ 29,163	
35	Total	$ 4,284,338	$ 4,353,336	
36				
37				
38	**Energy Billing Determinants (aMW)**	**2012**	**2013**	
39	Priority Firm Public - 7(b) Loads	6,874	6,966	
40	Priority Firm Exchange - 7(b) Loads	5,319	5,341	
41	Industrial Firm - 7(c) Loads	341	341	
42	New Resources - 7(f) Loads	0.001	0.001	
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2012**	**2013**	Average
47	Priority Firm Public - 7(b) Loads	30.04	30.50	**30.27**
48	Priority Firm Exchange - 7(b) Loads	54.11	54.48	**54.30**
49	Industrial Firm - 7(c) Loads	36.09	36.53	**36.31**
50	New Resources - 7(f) Loads	71.31	67.70	**69.50**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2011 to September 2013

	A	B	C	D	E	F	G	H
4						AggregationKey	**2012**	**2013**
5		**Composite**						
6			Federal Base System					
7				Hydro				
8					Operating Expense	CFHYOP	489,724	510,954
9					Interest	IFHYIT	172,194	181,568
10					MRNR	MFHYMR	33,201	13,581
11				Fish & Wildlife				
12					Operating Expense	CFFWOP	273,667	279,673
13					Interest	IFFWIT	17,980	20,095
14					MRNR	MFFWMR	3,467	1,503
15				Trojan		CFTR	1,500	1,500
16				WNP #1		CFW1	283,240	249,736
17				Columbia Generating Station		CFCG	421,919	446,117
18				WNP #3		CFW3	156,299	175,817
19				Augmentation		Internal	-	66,155
20				FBS Scenario Adjustment		Internal	-	-
21			Residentail Exchange Program					
22				REP Purchase Cost		Internal	2,814,996	2,818,228
23				REP Sale Revenue		Internal	(2,527,969)	(2,549,033)
24				Program Support		CRSP	1,446	885
25				Settlement		CRST	-	-
26			NewResources					
27				Cowlitz		CNCZ	14,838	14,879
28				Idaho		CNID	4,050	4,523
29				Tier 1 Aug (Klondike III)		CNTA	12,740	12,737
30				Other		CNOT	45,146	46,128
31				NR Scenario Adjustment		Internal	-	-
32			Conservation					
33				Operating Expense		CCOP	125,895	130,953
34				Interest		ICIT	17,634	17,220
35				MRNR		MCMR	3,400	1,288
36				Conservation Scenario Adjustment		Internal	-	-
37			BPAPrograms					
38				Operating Expense		CBOP	140,924	144,663
39				Interest		IBIT	994	2,663
40				MRNR		MBMR	192	199
41				BPA Programs Scenario Adjustment & Deemer Credit		Internal	-	-
42			Transmission					
43				Transmission and Ancillary Services		CTTA	44,793	44,726
44				General Transfer Agreements		CTGA	52,263	52,891
45				Transmission Scenario Adjustment		Internal	-	-
46			Nonslice Interest and MRNR Allocated to Cost Pools					
47				Interest on BPA fund Credit to Nonslice		Internal	1,362	(1,216)
48				Accrual Revenue (MRNR Adjustment)		Internal	(3,524)	(3,524)
49			**Total**			Internal	**2,602,370**	**2,684,909**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2011 to September 2013

	A	B	C	D	E	F	G	H
4						AggregationKey	**2012**	**2013**
50		**Non-Slice**						
51			FBS					
52				Balancing Purchases from Risk Mod		Internal	46,827	29,559
53				Balancing in Revenue Requirement		NFBL	44,529	43,073
54				PNRR				
55					Hydro	NFHYPR	-	-
56					Fish & Wildlife	NFFWPR	-	-
57			Conservation					
58				PNRR		NCPR	-	-
59			BPAPrograms					
60				Hedging Mitigation		NBHM	-	-
61				Bad Debt		NBOP	-	-
62				PNRR		NBPR	-	-
63			Transmission					
64				Transmission and Ancillary Services		NTTA	61,239	57,324
65				Third-partyT&A		NT3A	2,221	2,244
66			Nonslice Interest and MRNR					
67				BPAFund		NIBF	(1,362)	1,216
68				Non Slice MRNR Adjustment		NMAJ	3,524	3,524
69			**Total**			Internal	**156,979**	**136,940**
70		**Slice**						
71			BPAPrograms					
72				Other Slice Costs		SBSW	-	-
73			**Total**			Internal	-	-
74		**Tier 2**						
75			FBS					
76				Tier 2 Purchase Costs		2FT2PC	8,445	23,364
77				Tier 2 Rate Design Adjustments		2FT2RD	159	759
78				Tier 2 Other Costs		2FT2OT	-	-
79			**Total**			Internal	**8,604**	**24,123**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2011 to September 2013

	A	B	C	D	E	F	G	H
4						AggregationKey	**2012**	**2013**
80		**Rate Direct/Design Adjustments**						
81			Credits Allocated Against Cost Pools					
82				FBS (excluding T2 Adjustment)			(109,999)	(114,885)
83				Contract Obligations			(2,077)	(2,175)
84				New Resources			(2,658)	(2,836)
85				Conservation			(11,500)	(11,500)
86				BPAPrograms			-	-
87				Transmission			(3,420)	(3,420)
88								
89			Secondary Energy Credit (includes pre-sale)			Internal	(604,727)	(626,339)
90			Generation Inputs Credit			CDGI	(127,449)	(131,078)
91			Network Wind Credit			NDWI	(2,086)	(2,078)
92			Composite revenues associated with firm surplus sales			CDFC	(29,516)	(29,163)
93			Non-slice revenues associated with firm surplus sales			NDFC	(701)	(701)
94								
95			Low Density Discount			Internal	31,768	32,944
96			Irrigation Rate Mitigation Costs			Internal	19,305	19,305
97								
98			Composite Augmentation RSS Revenue Debit/(Credit)			CD2RCF	(2,015)	(2,015)
99			Composite Tier 2 RSS Revenue Debit/(Credit)			2D2RCF	(43)	(114)
100			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			2D2DC	(215)	(645)
101			Composite Non-Federal RSS Revenue Debit/(Credit)			CD2RCN	(474)	(482)
102			Non-Slice Augmentation RSC Revenue Debit/(Credit)			ND2RNF	(725)	(725)
103			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			2D2RNF	-	-
104			Non-Slice Tier 2 Rate Design Debit/(Credit)			2D2DN	98	-
105			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			ND2RNN	165	165
106								
107			Firm Surplus and Secondary Credit (from unused RHWM)			Internal	(19,469)	(5,827)
108			Demand Revenue			Internal	58,932	61,269
109			Load Shaping Revenue			Internal	(16,910)	(11,256)
110								

Table 2.5.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2011 to September 2013

	B	C	D
4		**2012**	**2013**
5	Secondary (aMW)	2,421	2,216
6	T1SFCO (aMW)	7,135	7,135
7	RHWM Augmentation (aMW)	46	46
8	RP Augmentation (aMW)	-	-
9	System Augmentation (aMW)	-	176
10	Augmentation Base (aMW)	46	222
11	IP and NR Loads contributing to avoided cost	350	350
12			
13	Value of Secondary	$ 27.56	$ 31.98
14	Value of T1SFCO ($/MWh)	$ 36.19	$ 36.19
15	Value of Augmentation	$ 37.78	$ 42.84
16			
17	Secondary (MWh)	21,266,330	19,410,580
18	T1SFCO (MWh)	62,673,840	62,502,600
19	RHWM Augmentation (MWh)	404,011	402,907
20	Augmentation Base (MWh)	404,011	1,947,152
21	IP and NR Loads (MWh)	3,077,753	3,069,344
22			
23	Unused RHWM (MWh)	2,524,937	1,788,391
24			
25	Unused Secondary	851,268	551,839
26	Unused T1SFCO	2,508,765	1,776,936
27	Unused Augmentation	16,172	11,455
28			
29	Value of Unused	$ 114,853,275	$ 82,436,224
30	Value of System Augmentation not Purchased	$ 95,384,679	$ 76,608,784
31			
32	Net Credit/(Cost)	$ 19,468,596	$ 5,827,440
33			
34	$/MWh value of Unused RHWM	**$ 45.74**	

Table 2.5.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2011 - September 2013

	B	C	D
4		**2012**	**2013**
5	**Non Slice Loads (MWh)**	43,324,247	44,077,091
6	**Loss Percent Assumption**	1.90%	1.90%
7	**Implied Non Slice Losses**	823,161	837,465
8	**Average Slice&Non-Slice Tier 1 Rate**	30.17	30.17
9	**Implied Cost/Credit ($1000)**	24,835	25,266

Table 2.5.4

Rate Design Step
Calculation of Load Shaping and Demand Revenues
Test Period October 2011 - September 2013

	B	E	F	G	H	I	J	K	L
5	**2012**	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	404,624	$ 9.18	$ 3,714,448	(94,042)	174,936	$ 37.86	$ 31.20	$ 1,897,569
7	Nov	389,557	$ 9.31	$ 3,626,776	(248,579)	100,648	$ 38.37	$ 31.40	$ (6,377,622)
8	Dec	900,108	$ 9.97	$ 8,974,077	161,064	368,441	$ 41.10	$ 33.39	$ 18,921,999
9	Jan	595,038	$ 9.70	$ 5,771,869	136,571	338,320	$ 40.03	$ 31.70	$ 16,191,654
10	Feb	520,155	$ 9.92	$ 5,159,938	223,528	275,901	$ 40.93	$ 33.17	$ 18,300,656
11	Mar	608,701	$ 9.60	$ 5,843,530	241,919	202,414	$ 39.57	$ 32.33	$ 16,116,797
12	Apr	437,157	$ 9.10	$ 3,978,129	393,468	325,253	$ 37.53	$ 30.41	$ 24,657,794
13	May	443,798	$ 8.50	$ 3,772,283	(994,666)	(383,374)	$ 35.06	$ 24.40	$ (44,227,326)
14	Jun	505,235	$ 8.72	$ 4,405,649	(599,801)	(154,194)	$ 35.97	$ 23.02	$ (25,124,374)
15	Jul	409,717	$ 10.20	$ 4,179,113	(724,284)	153,428	$ 42.07	$ 29.91	$ (25,881,587)
16	Aug	550,674	$ 10.75	$ 5,919,746	(186,213)	169,599	$ 44.35	$ 32.15	$ (2,805,921)
17	Sep	340,587	$ 10.53	$ 3,586,381	(294,287)	125,263	$ 43.45	$ 33.59	$ (8,579,186)
18	**Total**			**$ 58,931,937**					**$ (16,909,548)**
19									
20	**2013**	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	505,813	$ 9.18	$ 4,643,363	(61,266)	143,284	$ 37.86	$ 31.20	$ 2,150,909
22	Nov	409,627	$ 9.31	$ 3,813,627	(252,673)	103,611	$ 38.37	$ 31.40	$ (6,441,694)
23	Dec	789,985	$ 9.97	$ 7,876,150	117,231	423,419	$ 41.10	$ 33.39	$ 18,956,155
24	Jan	739,484	$ 9.70	$ 7,172,995	184,355	295,791	$ 40.03	$ 31.70	$ 16,756,329
25	Feb	489,035	$ 9.92	$ 4,851,227	283,469	315,502	$ 40.93	$ 33.17	$ 22,067,599
26	Mar	517,858	$ 9.60	$ 4,971,437	208,689	250,403	$ 39.57	$ 32.33	$ 16,353,366
27	Apr	554,710	$ 9.10	$ 5,047,861	431,883	293,504	$ 37.53	$ 30.41	$ 25,134,018
28	May	461,436	$ 8.50	$ 3,922,206	(1,012,850)	(390,520)	$ 35.06	$ 24.40	$ (45,039,186)
29	Jun	414,233	$ 8.72	$ 3,612,112	(641,839)	(129,604)	$ 35.97	$ 23.02	$ (26,070,420)
30	Jul	538,064	$ 10.20	$ 5,488,253	(689,850)	130,271	$ 42.07	$ 29.91	$ (25,125,600)
31	Aug	570,310	$ 10.75	$ 6,130,833	(177,054)	179,848	$ 44.35	$ 32.15	$ (2,070,210)
32	Sep	355,091	$ 10.53	$ 3,739,108	(286,437)	134,525	$ 43.45	$ 33.59	$ (7,926,999)
33	**Total**			**$ 61,269,172**					**$ (11,255,732)**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2011 - September 2013

	B	C	D	E
5	**Costs ($000)**	**2012**	**2013**	**Rate Period**
6	**Composite.......**	$ 2,602,371	$ 2,684,908	$ 5,287,279
7	**Non-Slice.......**	$ 156,979	$ 136,940	$ 293,919
8	**Slice.......**	$ -	$ -	$ -
9	**Tier 2.......**	$ 8,604	$ 24,123	$ 32,727
13				
14	**Revenues from Rate Pools to Composite Cost Pool**	**2012**	**2013**	**Rate Period**
15	DSI Revenue Credit.......	**$ (108,607)**	**$ (108,310)**	**$ (216,917)**
16	Exchange Revenues.......	**$ -**	**$ -**	**$ -**
17	New Resource Revenues.......	**$ (0.63)**	**$ (0.59)**	**$ (1)**
18	FPS Revenues.......	$ (29,516)	$ (29,163)	$ (58,679)
19	Non-Federal RSS Revenues.......	$ (474)	$ (482)	$ (956)
20	Other Credits.......	$ (257,103)	$ (265,893)	$ (522,996)
21	Tiered Rate Elements.......			$ -
22	Unused RHWM Credit Reallocation.......	$ (19,469)	$ (5,827)	$ (25,296)
23	Balancing Augmentation Adjustment Reallocation.......	$ 7,957	$ 6,268	$ 14,224
24	Composite Augmentation RSS Revenue Debit/(Credit)...	$ (2,015)	$ (2,015)	$ (4,030)
25	Composite Tier 2 RSS Revenue Debit/(Credit).......	$ (43)	$ (114)	$ (157)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$ (215)	$ (645)	$ (859)
27	Transmission Losses Adjustment Reallocation.......	$ (24,835)	$ (25,266)	$ (50,101)
28	Total.......	$ (434,319)	$ (431,449)	$ (865,768)
29				
30	**Rate Discount Costs Applied to Composite Pool**	**2012**	**2013**	**Rate Period**
31	Irigation Rate Discout Costs.......	$ 19,305	$ 19,305	$ 38,611
32	Low Density Discount Costs.......	$ 31,768	$ 32,944	$ 64,712
33	Total.......	$ 51,073	$ 52,249	$ 103,322
34				
35		**2012**	**2013**	**Rate Period**
36	**Composite.......**	$ 2,219,125	$ 2,305,708	$ 4,524,833

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2011 - September 2013

	B	C	D	E
5	**Costs ($000)**	**2012**	**2013**	**Rate Period**
6	**Composite**	$ 2,602,371	$ 2,684,908	$ 5,287,279
7	**Non-Slice**	$ 156,979	$ 136,940	$ 293,919
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 8,604	$ 24,123	$ 32,727
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2012**	**2013**	**Rate Period**
39	Secondary Revenue	$ (447,327)	$ (459,653)	$ (906,980)
40	Unused RHWM Credit Reallocation	$ 19,469	$ 5,827	$ 25,296
41	FPS Revenues not classified as Obligations in TRM	$ (701)	$ (701)	$ (1,402)
42	Non-federal RSC Revenues	$ 165	$ 165	$ 330
43	Network Wind Integration	$ (2,086)	$ (2,078)	$ (4,164)
44	Load Shaping Revenue	$ 16,910	$ 11,256	$ 28,165
45	Balancing Augmentation Adjustment Reallocation	$ (7,957)	$ (6,268)	$ (14,224)
46	Demand Revenue	$ (58,932)	$ (61,269)	$ (120,201)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (725)	$ (725)	$ (1,450)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -
49	Non-Slice Tier 2 Rate Design Debit/(Credit)	$ 98	$ -	$ 98
50	Transmission Losses Adjustment Reallocation	$ 24,835	$ 25,266	$ 50,101
51	Total	$ (456,252)	$ (488,180)	$ (944,432)
52				
53		**2012**	**2013**	**Rate Period**
54	**Non-Slice**	$ (299,273)	$ (351,240)	$ (650,513)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2011 - September 2013

	B	C	D	E
5	**Costs ($000)**	**2012**	**2013**	**Rate Period**
6	**Composite.....**	$ 2,602,371	$ 2,684,908	$ 5,287,279
7	**Non-Slice.....**	$ 156,979	$ 136,940	$ 293,919
8	**Slice.....**	$ -	$ -	$ -
9	**Tier 2.....**	$ 8,604	$ 24,123	$ 32,727
55				
56	**TRM Costs after Adjustments**	**2012**	**2013**	**Rate Period**
57	**Composite.....**	$ 2,219,125	$ 2,305,708	$ 4,524,833
58	**Non-Slice.....**	$ (299,273)	$ (351,240)	$ (650,513)
59	**Slice.....**	$ -	$ -	$ -
60	**Tier 2.....**	$ 8,604	$ 24,123	$ 32,727
61	**Total Costs**	$ 1,928,456	$ 1,978,591	$ 3,907,047
62				
63	**Billing Determinants**	**2012**	**2013**	**Rate Period**
64	**TOCA.....**	96.00	97.16	97
65	**Non-slice TOCA.....**	69	70	70
66	**Slice Percentage.....**	27	27	27
67				
68	**Annual TRM Rates ($000/percent)**	**2012**	**2013**	**Rate Period**
69	**Composite.....**	$ 23,117	$ 23,732	$ 23,426
70	**Non-Slice.....**	$ (4,328)	$ (4,996)	$ (4,665)
71	**Slice.....**	$ -	$ -	$ -
72				
73	**Monthly TRM Rates ($/percent)**	**2012**	**2013**	**Rate Period**
74	**Composite.....**	1,926,382	1,977,648	1,952,169
75	**Non-Slice.....**	(360,692)	(416,340)	(388,748)
76	**Slice.....**	-	-	-
77				
78	**Tier 2 Rates ($/MWh)**	**2012**	**2013**	**Rate Period**
79	**Tier 2 Short Term.....**	$ 46.48	$ 48.69	$ 47.59
80	**Tier 2 Load Growth.....**	$ -	$ 48.63	$ 48.63

Table 2.5.6.1

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2011 - September 2013
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			**2010**	**2011**		**PF p**	**IP**	**NR**	**FPS**				**PF p**	**IP**	**NR**
12	GENERATION ENERGY														
13													121,404	5,974	0.017544
14	Federal Base System														
15	Hydro		695,120	706,103		1,401,223	0.0	0.0	0				11.54	0.00	0.00
16	Fish & Wildlife		295,114	301,271		596,384	0.0	0.0	0				4.91	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		283,240	249,736		532,976	0.0	0.0	0				4.39	0.00	0.00
19	WNP #2		421,919	446,117		868,036	0.0	0.0	0				7.15	0.00	0.00
20	WNP #3		156,299	175,817		332,116	0.0	0.0	0				2.74	0.00	0.00
21	System Augmentation		0	66,155		66,155	0.0	0.0	0				0.55	0.00	0.00
22	Balancing Power Purchases		91,357	72,632		163,989	0.0	0.0	0				1.35	0.00	0.00
23	Tier 2 Costs		8,604	24,123		32,727	0.0	0.0	0				0.27	0.00	0.00
25	Total Federal Base System		1,953,152	2,043,454		3,996,606	0.0	0.0	0.0				32.92	0.00	0.00
26															
27	New Resources		74,034	75,527		149,561	0.0	0.0	0		PFx Revenue		1.23	0.00	0.00
29	Residential Exchange		2,621,610	2,624,023		558,553	0.0	0.0	0		4,687,080		4.60	0.00	0.00
30	Conservation		146,929	149,461		296,390	0.0	0.0	0				2.44	0.00	0.00
32	BPA Programs & Transmission		302,625	304,710		607,335	0.0	0.0	0		NR Revenue		5.00	0.00	0.00
34	TOTAL COSA ALLOCATIONS		5,098,350	5,197,174		5,608,445	0	0	0		1.2		46.20	0.00	0.00
35															
36															
37	Nonfirm Excess Revenue Credit		(604,727)	(626,339)		(1,231,066)	0.0	0.0	0.0				-10.14	0.00	0.00
38	LDD/IRD Expense		51,073	52,249		103,322	0.0						0.85	0.00	0.00
39	Other Revenue Credits		(260,359)	(269,749)		(530,107)	0.0	0.0	0.0				-4.37	0.00	0.00
40						0	0.0						0.00	0.00	0.00
41	SP Revenue Surplus/Dfct Adj.		0	0		(58,679)	0	0.0	58,679				-0.48	0.00	0.00
42						(1.2)		1.2194					0.00	0.00	69.51
43	IP Rate Revenue		0	0		(216,916)	216,916						-1.79	36.31	0.00
44															
45	TOTAL RATE DESIGN ADJUSTMENTS		(814,012)	(843,839)		(1,933,447)	216,916	1.2	58,679				-15.93	36.31	69.51
46															
47	Total Generation		4,284,338	4,353,336									**30.27**	**36.31**	**69.51**
48				**PFp Revenue Recovery**		**3,674,998**	216,916	1.2	58,679						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2011 to September 30, 2013

	G	H		I		J
5						
6						
7	**Proof: TRM PF Revenues = Non-TRM PF Revenues**					
8						
9			2012		2013	
10	Composite Revenue............................	$	2,219,125	$	2,305,710	
11	Non-Slice Revenue..............................	$	(299,273)	$	(351,240)	
12	Slice Revenue......................................	$	-	$	-	
13	Tier 2..	$	8,604	$	24,123	
14	Load Shaping Revenue.........................	$	(16,910)	$	(11,256)	
15	Demand Revenue................................	$	58,932	$	61,269	
16	Total TRM PF Revenue	$	1,970,479	$	2,028,606	
17						
18	Slice Portion of Secondary Revenue.....	$	(157,400)	$	(166,686)	
19	Total Net TRM PF Revenue	$	1,813,080	$	1,861,919	
20						
21						PF Rate
22	Total TRM PF Revenue Analogous to w/ Slice PF			$	3,674,999	30.27
23						
24	w/ Slice PF Public Rate Revenue from "Net REP" Table			**$**	**3,674,998**	30.27
25			delta	$	(1)	
26						

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2011 - September 2013

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		
15	HLH (mills/kWh)	37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45		
16	LLH (mills/kWh)	31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59		
17	Demand Rate ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	5,541	6,243	7,017	6,952	5,982	6,008	5,110	5,951	5,674	6,301	6,025	5,420		120,724
22	LLH (GWh)	3,541	4,391	4,952	4,946	4,050	4,059	3,491	4,028	3,553	4,037	3,691	3,764		Tier 1 Demand (MW/mo)
23	Demand (MW)	910	799	1,690	1,335	1,009	1,127	992	905	919	948	1,121	696		12,451
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)	$ 209,781	$ 239,525	$ 288,360	$ 278,263	$ 244,816	$ 237,757	$ 191,747	$ 208,635	$ 204,107	$ 265,102	$ 267,209	$ 235,521	$	4,358,923
29	LLH ($000)	$ 110,481	$ 137,884	$ 165,341	$ 156,775	$ 134,326	$ 131,222	$ 106,173	$ 98,290	$ 81,788	$ 120,740	$ 118,652	$ 126,430		Demand Revenue ($000)
30	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325	$	120,201
31														$	4,479,124
32															Tier 1 Revenue Requirement (RR) ($000)
33														$	3,642,274
34															Tier 1 RR less Demand Revenue ($000)
35														$	3,522,073
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)	30.93	31.44	34.17	33.10	34.00	32.64	30.60	28.13	29.04	35.14	37.42	36.52		6.93
38	LLH (mills/kWh)	24.27	24.47	26.46	24.77	26.24	25.40	23.48	17.47	16.09	22.98	25.22	26.66		
39	Demand ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	$ 171,382	$ 196,277	$ 239,759	$ 230,111	$ 203,372	$ 196,100	$ 156,351	$ 167,396	$ 164,784	$ 221,413	$ 225,451	$ 197,941	$	3,522,320
45	LLH ($000)	$ 85,941	$ 107,453	$ 131,025	$ 122,502	$ 106,262	$ 103,094	$ 81,977	$ 70,374	$ 57,166	$ 92,765	$ 93,076	$ 100,346		Allocated Cost Demand ($000)
46	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325	$	120,201
47														$	3,642,521

	C	D	E
48	Average Slice&Non-Slice Tier 1 Rate		
49		($000)	(mills/kWh)
50	Allocated Cost Energy	$ 3,522,320	29.18
51	Allocated Cost Demand	$ 120,201	1.00
52	Total Allocated Costs	$ 3,642,521	30.17
53			
54	Tier 1 Energy (GWh)		120,724
55	Market Energy Delta (mills/kWh)		6.93

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2011 - September 2013

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		
15	HLH (mills/kWh)	37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45		
16	LLH (mills/kWh)	31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59		
17	Demand Rate ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	5,573	6,273	7,047	6,983	6,011	6,040	5,140	5,982	5,705	6,332	6,057	5,449		121,404
22	LLH (GWh)	3,567	4,417	4,979	4,972	4,073	4,085	3,516	4,055	3,578	4,064	3,716	3,791		Tier 1 Demand (MW/mo)
23	Demand (MW)	910	799	1,690	1,335	1,009	1,127	992	905	919	948	1,121	696		12,451
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)	$ 210,998	$ 240,678	$ 289,622	$ 279,514	$ 246,011	$ 239,008	$ 192,908	$ 209,730	$ 205,200	$ 266,404	$ 268,648	$ 236,775		$ 4,383,056
29	LLH ($000)	$ 111,277	$ 138,694	$ 166,241	$ 157,612	$ 135,102	$ 132,063	$ 106,929	$ 98,934	$ 82,373	$ 121,539	$ 119,462	$ 127,335		Demand Revenue ($000)
30	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325		$ 120,201
31															$ 4,503,257
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 3,675,001
34															T1&2RR less Demand Revenue ($000)
35															$ 3,554,800
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)	31.04	31.55	34.28	33.21	34.11	32.75	30.71	28.24	29.15	35.25	37.53	36.63		6.82
38	LLH (mills/kWh)	24.38	24.58	26.57	24.88	26.35	25.51	23.59	17.58	16.20	23.09	25.33	26.77		
39	Demand ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	$ 172,989	$ 197,912	$ 241,583	$ 231,913	$ 205,025	$ 197,796	$ 157,863	$ 168,933	$ 166,294	$ 223,197	$ 227,332	$ 199,594		$ 3,555,098
45	LLH ($000)	$ 86,953	$ 108,570	$ 132,286	$ 123,703	$ 107,324	$ 104,204	$ 82,948	$ 71,281	$ 57,969	$ 93,826	$ 94,120	$ 101,482		Allocated Cost Demand ($000)
46	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325		$ 120,201
47															$ 3,675,299
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,555,098	29.28												
51	Allocated Cost Demand	$ 120,201	0.99												
52	Total Allocated Costs	$ 3,675,299	30.27												
53															
54	Tier 1&2 Energy (GWh)		121,404												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		6.82												

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2011 - September 2013

PF Melded Eqv Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	31.04	31.55	34.28	33.21	34.11	32.75	30.71	28.24	29.15	35.25	37.53	36.63
LLH (mills/kWh)	24.38	24.58	26.57	24.88	26.35	25.51	23.59	17.58	16.20	23.09	25.33	26.77
Demand Rate ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	**Totals**
													IP Energy (GWh)
HLH (GWh)	289	272	278	278	267	289	278	283	278	278	294	262	5,974
LLH (GWh)	218	219	229	229	199	217	212	223	212	229	212	229	
Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-	

Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Energy Rev & Tier1&2 ($000)
HLH ($000)	$ 8,963	$ 8,594	$ 9,525	$ 9,227	$ 9,106	$ 9,456	$ 8,533	$ 8,000	$ 8,099	$ 9,794	$ 11,041	$ 9,579	$ 172,329
LLH ($000)	$ 5,313	$ 5,373	$ 6,080	$ 5,693	$ 5,240	$ 5,542	$ 5,012	$ 3,927	$ 3,442	$ 5,283	$ 5,382	$ 6,125	Demand Rev ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 172,329

VOR (mills/kWh)	(0.94)
Industrial Margin (mills/kWh)	0.685
Net industrial Margin	(0.256)
Settlement Charge	7.723

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10
LLH (mills/kWh)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.80	34.24
Demand ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Allocated Cost Energy ($000)
HLH ($000)	$ 11,120	$ 10,629	$ 11,600	$ 11,303	$ 11,100	$ 11,613	$ 10,608	$ 10,117	$ 10,175	$ 11,870	$ 13,239	$ 11,532	$ 216,953
LLH ($000)	$ 6,941	$ 7,006	$ 7,789	$ 7,402	$ 6,725	$ 7,165	$ 6,599	$ 5,595	$ 5,029	$ 6,993	$ 6,969	$ 7,835	Allocated Cost Demand ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 216,953

Average IP Rate	($000)	(mills/kWh)
Allocated Cost Energy	$ 216,953	36.32
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 216,953	36.32
IP Energy (GWh)		5,974
Industrial Margin (mills/kWh)		0.68
VOR (mills/kWh)		(0.94)
Settlement Charge		7.72

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2011 - September 2013

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		
15	HLH (mills/kWh)	37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45		
16	LLH (mills/kWh)	31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59		
17	Demand Rate ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0009	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0006	0.0007	0.0007	0.0006	0.0006	0.0006	0.0007	0.0006	0.0007	0.0006	0.0007		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)	$ 0.0321	$ 0.0307	$ 0.0335	$ 0.0327	$ 0.0321	$ 0.0336	$ 0.0306	$ 0.0292	$ 0.0294	$ 0.0343	$ 0.0383	$ 0.0334		$ 0.6258
29	LLH ($000)	$ 0.0200	$ 0.0202	$ 0.0224	$ 0.0213	$ 0.0194	$ 0.0206	$ 0.0190	$ 0.0160	$ 0.0144	$ 0.0201	$ 0.0201	$ 0.0226		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.6258
32															NR Revenue Requirement (RR) ($000)
33															$ 1.2194
34															NR RR less Demand Revenue ($000)
35															$ 1.2194
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	71.70	72.21	74.94	73.87	74.77	73.41	71.37	68.90	69.81	75.91	78.19	77.29		(33.84)
38	LLH (mills/kWh)	65.04	65.24	67.23	65.54	67.01	66.17	64.25	58.24	56.86	63.75	65.99	67.43		
39	Demand ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	$ 0.0608	$ 0.0578	$ 0.0611	$ 0.0603	$ 0.0586	$ 0.0623	$ 0.0582	$ 0.0573	$ 0.0570	$ 0.0619	$ 0.0676	$ 0.0594		$ 1.2194
45	LLH ($000)	$ 0.0416	$ 0.0419	$ 0.0452	$ 0.0440	$ 0.0391	$ 0.0422	$ 0.0401	$ 0.0382	$ 0.0355	$ 0.0428	$ 0.0412	$ 0.0453		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.2194
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.2194	69.51												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.2194	69.51												
53															
54		NR Energy (GWh)	0.0175												
55															

Table 2.5.7.5

Rate Design Step
Calculation of Load Shaping True-Up Rate
Test Period October 2011 - September 2013

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12		
15	HLH (mills/kWh)	37.86	38.37	41.10	40.03	40.93	39.57	37.53	35.06	35.97	42.07	44.35	43.45		
16	LLH (mills/kWh)	31.20	31.40	33.39	31.70	33.17	32.33	30.41	24.40	23.02	29.91	32.15	33.59		
17	Demand Rate ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	3,974	4,383	5,133	5,099	4,475	4,480	3,935	3,754	3,767	4,172	4,266	3,767		87,401
22	LLH (GWh) [FMDT1L]	2,659	3,241	3,836	3,788	3,101	3,070	2,706	2,707	2,500	3,008	2,775	2,804		Tier 1 Demand (MW/mo)
23	Demand (MW)	910	799	1,690	1,335	1,009	1,127	992	905	919	948	1,121	696		12,451
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000) [MktR]
28	HLH ($000)	$ 150,457	$ 168,178	$ 210,968	$ 204,079	$ 183,147	$ 177,289	$ 147,658	$ 131,627	$ 135,494	$ 175,546	$ 189,190	$ 163,683		$ 3,151,623
29	LLH ($000)	$ 82,959	$ 101,777	$ 128,071	$ 120,065	$ 102,854	$ 99,268	$ 82,300	$ 66,062	$ 57,542	$ 89,981	$ 89,228	$ 94,200		Demand Revenue ($000)
30	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325		$ 120,201
31															$ 3,271,824
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															$ 2,708,295
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 2,588,093
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)	31.41	31.92	34.65	33.58	34.48	33.12	31.08	28.61	29.52	35.62	37.90	37.00		6.45
38	LLH (mills/kWh)	24.75	24.95	26.94	25.25	26.72	25.88	23.96	17.95	16.57	23.46	25.70	27.14		
39	Demand ($/kW/mo)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53		
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)	$ 124,824	$ 139,916	$ 177,875	$ 171,212	$ 154,290	$ 148,377	$ 122,290	$ 107,412	$ 111,198	$ 148,619	$ 161,672	$ 139,374		$ 2,587,899
45	LLH ($000)	$ 65,809	$ 80,870	$ 103,331	$ 95,636	$ 82,853	$ 79,464	$ 64,844	$ 48,599	$ 41,419	$ 70,577	$ 71,327	$ 76,112		Allocated Cost Demand ($000)
46	Demand ($000)	$ 8,358	$ 7,440	$ 16,850	$ 12,945	$ 10,011	$ 10,815	$ 9,026	$ 7,694	$ 8,018	$ 9,667	$ 12,051	$ 7,325		$ 120,201
47															$ 2,708,100
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 2,587,899	29.61												
51	Allocated Cost Demand	$ 120,201	1.38												
52	Total Allocated Costs	$ 2,708,100	30.98												
53															
54	Tier 1 Energy (GWh) [FAT1L]		87,401												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		6.45												

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2011 - September 2013

	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	1,401,223	6.520	16.77%		791,556	6.520	609,666	6.520	
19		Fish & Wildlife	596,384	2.775	7.14%		336,900	2.775	259,484	2.775	
20		Trojan	3,000	0.014	0.04%		1,695	0.014	1,305	0.014	
21		WNP #1	532,976	2.480	6.38%		301,080	2.480	231,896	2.480	
22		WNP #2	868,036	4.039	10.39%		490,357	4.039	377,679	4.039	
23		WNP #3	332,116	1.545	3.97%		187,614	1.545	144,502	1.545	
24		System Augmentation	66,155	0.308	0.79%		37,371	0.308	28,784	0.308	
25		Balancing Power Purchases	163,989	0.763	1.96%		92,638	0.763	71,351	0.763	
26		Tier 2 Costs	32,727	0.152	0.39%		18,488	0.152	14,239	0.152	
27		Total Federal Base System	3,996,606	18.597	47.82%		2,257,699	18.597	1,738,907	18.597	
28		New Resources									
29		Gross Residential Exchange	4,929,387	22.937	58.99%		2,784,631	22.937	2,144,756	22.937	
30		Conservation	286,274	1.332	3.43%		161,718	1.332	124,557	1.332	
31		BPA Programs	279,750	1.302	3.35%		158,032	1.302	121,718	1.302	
32		Power Transmission	306,856	1.428	3.67%		173,344	1.428	133,512	1.428	
33		TOTAL COSA ALLOCATIONS	9,798,874	45.595	117.26%		5,535,424	45.595	4,263,449	45.595	
34											
35											
36		Nonfirm Excess Revenue Credit	(1,212,363)	-5.641	-14.51%		(684,869)	-5.641	(527,494)	-5.641	
37		Low Density Discount Expense	103,322	0.481	1.24%		58,367	0.481	44,955	0.481	
38		Other Revenue Credits	(514,608)	-2.395	-6.16%		(290,704)	-2.395	(223,904)	-2.395	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	38,926	0.181	0.47%		21,989	0.181	16,936	0.181	
41		7(c)(2) Delta Adjustment	142,602	0.664	1.71%		80,557	0.664	62,046	0.664	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,442,121)	-6.710	-17.26%		(814,660)	-6.710	(627,461)	-6.710	
44											
45		Total Generation	8,356,753	**38.88**	100.00%		4,720,764	**38.88**	3,635,989	**38.88**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,095,109)	-9.020	1,051,138	1,051,138	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					49,299	0.406	2	0.000	
50		Total Generation					**3,674,954**	**30.27**	4,687,128	**50.13**	
51											
52		Total Transmission							389,923	4.170	
53									5,077,051	**54.30**	
54											

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2011 - September 2013

	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	117,646	19.694	54.24%
28	Gross Residential Exchange	248,756	41.642	114.68%
29	Conservation	7,957	1.332	3.67%
30	BPA Programs	7,775	1.302	3.58%
31	Power Transmission	8,530	1.428	3.93%
32	TOTAL COSA ALLOCATIONS	390,665	65.397	180.11%
33				
34	Nonfirm Excess Revenue Credit	(14,712)	-2.463	-6.78%
35				
36	Other Revenue Credits	(12,192)	-2.041	-5.62%
37				
38	SP Revenue Surplus/Dfct Adj.	1,082	0.181	0.50%
39	7(c)(2) Delta Adjustment	(142,602)	-23.872	-65.74%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(168,424)	-28.194	-77.65%
42	Total Generation	222,241	37.203	102.46%
43				
55	Total Allocated & Adjusted Costs	222,241	37.203	102.46%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	43,971	7.361	20.27%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(49,299)	-8.253	-22.73%
60		216,913	**36.31**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	5,974		

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2011 - September 2013

	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	0.3455	19.694	28.33%
27	Gross Residential Exchange	0.7306	41.642	59.91%
28	Conservation	0.0234	1.332	1.92%
29	BPA Programs	0.0479	2.730	3.93%
30	TOTAL COSA ALLOCATIONS	1.1473	65.397	94.09%
31				
32	Nonfirm Excess Revenue Credit	(0.0432)	-2.463	-3.54%
33				
34	Other Revenue Credits	(0.0358)	-2.041	-2.94%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0032	0.181	0.26%
37	7(c)(2) Delta Adjustment	0.0116	0.664	0.96%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0642)	-3.659	-5.26%
40	Total Generation Energy	1.0831	61.738	88.83%
41				
50				
51	Total Allocated & Adjusted Costs	1.0831	61.738	88.83%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1291	7.361	10.59%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0071	0.406	0.58%
55				
56	Total With 7(b)(2) Adjustments	1.2194	**69.51**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01754		

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2011 - September 2013

	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	2,257,699	2,784,631		5,042,331		44.77%	55.23%		100.00%
18	Priority Firm - Exchange	1,738,907	2,144,756		3,883,663		44.77%	55.23%		100.00%
19	Priority Firm Power - Total	3,996,606	4,929,387		8,925,993		44.77%	55.23%		100.00%
20	Industrial Firm Power		248,756	117,646	366,402			67.89%	32.11%	100.00%
21	New Resources Firm		0.731	0	1			67.89%	32.11%	100.00%
22	Firm Power Products and Services		67,488	31,915	99,403			67.89%	32.11%	100.00%
23										
24										
25	**TOTALS**	**3,996,606**	**5,245,633**	**149,561**	**9,391,799**		**42.55%**	**55.85%**	**1.59%**	**100.00%**
26										
27					220,884					
28										
29				Average Cost of Resources	42.52					
30										
31				Average Cost to Serve Load Growth	47.93					

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

Table 3.3
Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit and to calculate the TSS cost adder.

Table 3.4
Load Shaping Rates
Table includes the calculation of the Load Shaping rates and the flat annual block Aurora market price forecast

Table 3.5
Tier 1 Demand Rates
Table includes the calculation of the Tier 1 Demand rate.

Table 3.6
Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.7
Inputs to TSS Rate and Charge
Table shows the costs used as the numerator and the megawatthours 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
Table is the 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
Table is the costing table used to calculate the Tier 2 Load Growth rates for each year of the rate period.

Table 3.10
Tier 2 Purchases Made by BPA
Table lists information pertaining to Mid-C purchases made by BPA to meet Tier 2 rate load obligations.

Table 3.11
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 3.12
Fixed Irrigation Rate Mitigation Program Percentage
Table shows the calculation of the fixed IRMP Percentage; calculation done in accordance with section 10.3 of the Tiered Rate Methodology.

Table 3.13
FY2009 Irrigation Rate Mitigation Program Data
Table shows the FY2009 IRMP data used to calculate the fixed IRMP percentage.

Table 3.14
Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' FY2011 LDD percentages and the qualifying irrigation load amounts from the customers' CHWM Contracts.

Table 3.15
Sample RSS Resource Output Data
Table summarizes the sample resource data for the illustrative RSS examples that follow.

Table 3.16
Rates and Charges for RSS and Related Services Applied to Sample Resources
Table summarizes the RSS model results for the illustrative RSS examples. This table also shows which service, during which year, and for what resource. The table also summarizes the revenue credits by sample customer and resource 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 3.17
Solar Resource DFS Example
Table illustrates how the model calculates both the DFS Energy costs to produce the DFS Energy rate and DFS Capacity costs to produce the DFS Capacity charge for a sample solar resource.

Table 3.18
Solar Resource RSC Example
Table illustrates how the model calculates the Resource Shaping costs to produce the Resource Shaping charge for a sample solar resource.

Table 3.19
Biomass Resource DFS Example
Table illustrates how the model calculates both the DFS Energy costs to produce the DFS Energy rate and DFS Capacity costs to produce the DFS Capacity charge for a sample biomass resource.

Table 3.20
Biomass Resource RSC, FORS, and TSS Example
Table illustrates how the model calculates the Resource Shaping costs to produce the Resource Shaping charge for a sample biomass resource. Also shown are the calculations to produce a FORS Capacity charge and TSS charge.

Table 3.21
Wind Resource DFS Example
Table illustrates how the model calculates both the DFS Energy costs to produce the DFS Energy rate and DFS Capacity costs to produce the DFS Capacity charge for a sample wind resource.

Table 3.22
Biomass Resource RSC and TSS Example
Table illustrates how the model calculates the Resource Shaping costs to produce the Resource Shaping charge for a sample wind resource. Also shown are the calculations to produce a TSS charge.

Table 3.23
Rates and Charges for RSS and Related Services in FY 2012 and FY 2013
Table summarizes the RSS model 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 3.24
Irrigation Rate Discount (IRD) HLH/LLH Split
Table shows historical HLH/LLH splits on irrigation loads; analysis is based on FY2006-FY2009 meter data.

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Table 3.1
Summary RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G	H	I	J
1					2012	2013	2014	2015	2016	2017
2	TRM	COSA	AggregationKey	Category						
3	C	RDS	CNTA	Augmentation RSS & RSC Adder (RSS)	2,739.8	2,015.1	2,015.1	2,015.1	2,015.1	2,015.1
4	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	-2,015.1	-2,015.1	-2,015.1	-2,015.1	-2,015.1	-2,015.1
5	2	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
6	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	-474.1	-482.0	-482.0	-482.0	-482.0	-482.0
7	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	-724.8	-724.8	-724.8	-724.8	-724.8	-724.8
8	2	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
9	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	164.8	164.8	164.8	164.8	164.8	164.8

Table 3.2
Tier 2 Rate Revenues

	B	C	D
1	Tier2RateRev&Pool		
2	**Tier2PricingModel.xls**		
3			
4	Hours	8,784	8,760
5	Notice	Nov 1, 2009	
6	Fiscal Year	FY2012	FY2013
7	Rate Period	WP-12	
8	ST.1.2012_2014 Rate $/MWh	$ 46.48	$ 48.69
9	LG.1.2012_2028 Rate $/MWh	$ -	$ 48.63
10			
11	ST.1.2012_2014	Term (Years)	3
12	Portfolio Purchased aMW	22.000	55.300
13	Portfolio Purchased MWh	193,248	484,428
14	Portfolio Obligation /w Losses aMW	21.667	55.406
15	Portfolio Obligation /w Losses MWh	190,323	485,357
16	Portfolio Billing Determinant aMW	21.073	53.886
17	Portfolio Billing Determinant MWh	185,105	472,041
18	RECs MWh	0	0
19	Base Power Purchase Cost	$ 8,444,938	$ 22,276,330
20	Rate Design Components	$ 159,343	$ 705,445
21	Other Costs	$ -	$ -
22	Rate $/MWh	$ 46.48	$ 48.69
23	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (214,642)	$ (557,099)
24	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (42,574)	$ (108,570)
26	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (39,776)
27	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ 97,873	$ -
28	Total ST.1.2012_2014 Revenue	$ 8,603,691	$ 22,983,694
29			
30	LG.1.2012_2028	Term (Years)	17
31	Portfolio Purchased aMW	0.000	2.700
32	Portfolio Purchased MWh	0	23,652
33	Portfolio Obligation /w Losses aMW	0.000	2.754
34	Portfolio Obligation /w Losses MWh	0	24,125
35	Portfolio Billing Determinant aMW	0.000	2.678
36	Portfolio Billing Determinant MWh	0	23,459
37	RECs MWh	0	0
38	Base Power Purchase Cost	$ -	$ 1,087,466
39	Rate Design Components	$ -	$ 53,346
40	Other Costs	$ -	$ -
41	Rate $/MWh	$ -	$ 48.63
42	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ -	$ (27,686)
43	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
44	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ -	$ (5,396)
45	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (20,263)
46	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
47	Total LG.1.2012_2028 Revenue	$ -	$ 1,140,825
48			
49	Total Tier 2 Revenue Collection	$ 8,603,691	$ 24,124,519
50			
51	Total Tier 2 Adjustments and Credits*		
52	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (214,642)	$ (584,785)
53	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
54	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (42,574)	$ (113,965)
55	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (60,040)
56	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ 97,873	$ -
57			
58	*This amount is in addition to any RSS credits that result from the RSS model		

Table 3.3
Tier 2 Inputs

	B	C	D	E	F
1	RateInputs				
2	Tier2PricingModel.xls				
3					
4					
5	Fiscal Year	$/MWh TSS Rate	Aurora Flat Annual Block Market Forecast ($/MWh)	Augmentation Price ($/MWh)	Augmentation Amount (MWh)
6	FY2012	$ 0.23	$ 33.46	$ 37.78	-
7	FY2013	$ 0.23	$ 37.87	$ 42.84	1,544,244

Table 3.4
Load Shaping Rates

	A	B	C	D	E	F	G	H	I
1									
2									
3			Aurora Market Prices				Load Shaping Rates		
4			HLH - $/MWh	LLH - $/MWh			HLH - $/MWh	LLH - $/MWh	
5		Oct-11	34.79	28.39		October	37.86	31.20	
6		Nov-11	36.42	29.87		November	38.37	31.40	
7		Dec-11	39.02	31.79		December	41.10	33.39	
8		Jan-12	37.18	29.51		January	40.03	31.70	
9		Feb-12	37.62	30.63		February	40.93	33.17	
10		Mar-12	36.29	29.69		March	39.57	32.33	
11		Apr-12	35.09	28.10		April	37.53	30.41	
12		May-12	33.04	22.44		May	35.06	24.40	
13		Jun-12	34.13	21.95		June	35.97	23.02	
14		Jul-12	40.58	29.00		July	42.07	29.91	
15		Aug-12	42.21	30.67		August	44.35	32.15	
16		Sep-12	40.78	31.55		September	43.45	33.59	
17		Oct-12	40.93	34.00					
18		Nov-12	40.31	32.94				$/MWh	
19		Dec-12	43.17	35.00		FY2012 Aurora Flat Annual Block		33.46	
20		Jan-13	42.87	33.89		FY2013 Aurora Flat Annual Block		37.87	
21		Feb-13	44.24	35.70					
22		Mar-13	42.85	34.98					
23		Apr-13	39.96	32.71					
24		May-13	37.08	26.36					
25		Jun-13	37.81	24.08					
26		Jul-13	43.57	30.83					
27		Aug-13	46.49	33.62					
28		Sep-13	46.13	35.64					
29									
30									
31									
32									
33									

Table 3.5
Tier 1 Demand Rates

Row	D	E	F
3	Start Year of Operation (FY)	2012	
4	Cost of Debt	4.71%	/1
5			
6	Inflation Rate	2.05%	
7	Insurance Rate	0.25%	/2
8			
9	Debt Finance Period (years)	30	/2
10	Plant Lifecycle (years)	30	/2
11			
12	Plant in service 2012 Vintaged Heat Rate Btu/kWh	8,738	/2
13			
14	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2
15	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 45.95	/2
16	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 38.06	
17	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 51.89	
18	Average of Existing and New with 10000 Heat Rate 2012$	$ 44.98	
19	Average of Existing and New with 8738 Heat Rate 2012$	$ 39.30	
20			
21	All-in Nominal Capital Cost LMS100 $/kW	$ 1,081.00	/2
22	Fixed O&M $/kW/yr 2012$	$ 9.03	/3
23	Fixed Fuel adjusted for 10% capacity release credit $/kW/yr	$ 35.37	

Calendar Year	Chained GDP IPD	
2005	100.00	
2006	103.26	
2007	106.30	
2008	108.62	
2009	109.62	
2010	110.66	
	102.05%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product - Last Revised May 26, 2011

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	37.86	7.95%	$ 9.18
Nov	38.37	8.06%	$ 9.31
Dec	41.10	8.63%	$ 9.97
Jan	40.03	8.40%	$ 9.70
Feb	40.93	8.59%	$ 9.92
Mar	39.57	8.31%	$ 9.60
Apr	37.53	7.88%	$ 9.10
May	35.06	7.36%	$ 8.50
Jun	35.97	7.55%	$ 8.72
Jul	42.07	8.83%	$ 10.20
Aug	44.35	9.31%	$ 10.75
Sep	43.45	9.12%	$ 10.53
	Average $/kW/mo		$ 9.62

End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
2012	$ 1,062.98	$68.01	$ 9.03	$ 2.66	$ 35.37	$115.07
2013	$ 1,026.95	$68.01	$ 9.21	$ 2.57	$ 36.09	$115.89
				Rate Period Average Expe		$ 115.48

/1 Source BPA FY 2012 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year

/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.71% with plant in service 2012 and PNWE fixed fuel. Version 14.2.11

/3 Source NWPCC Microfin Model assumption of $8/kW/yr in 2006$

Table 3.6
Tier 2 Overhead Adder Inputs

	B	C	D	E	F
1	**OverheadCosts**				
2	**Tier2PricingModel.xls**				
3					
4		**WP-12**			
5		**FY2012**		**FY2013**	
6	**Line Item**	**FY2012**	**Total Forecast Sales (MWh)**	**FY2013**	**Total Forecast Sales (MWh)**
7	Executive and Administrative Services	$ 3,557,110	83,166,630	$ 3,619,809	82,428,573
8	Generation Project Coordination	$ 5,894,831		$ 5,918,558	
9	Sales & Support	$ 19,744,831		$ 20,130,099	
10	Strategy, Finance & Risk Mgmt	$ 17,245,842		$ 18,044,914	
11	Agency Services G&A	$ 49,994,526		$ 49,568,070	
12	Updated based upon 9/23/10 Version				

Table 3.7
Inputs to TSS Rate and Charge

	K	L	M	N
4	**PTK Costs FY2012**	**PTK Costs FY2013**	**FY2009 Scheduled (MWh)**	**FY2010 Scheduled (MWh)**
5	$ 5,155,354	$ 5,246,876	22,615,665	23,107,613

Table 3.8
Tier 2 Short-Term Rate Costing Table

	B	C		D	
1	**ST.1.2012_2014**				
2	**Tier2PricingModel.xls**				
3					
4	Hours		8,784		8,760
5	Notice	Nov 1, 2009			
6	Fiscal Year	FY2012		FY2013	
7	Rate Period	WP-12			
8	ST.1.2012_2014				
9	**Total Forecast Expected Cost**	$	8,604,281	$	22,981,774
10	Base Power Purchase Cost (Provided by PTL)	$	8,444,938	$	22,276,330
11	Power Purchase Cost	$	8,444,938	$	22,276,330
12	Transmission	$	-	$	-
13	*Third Party PTP*				
14	*Ancillary Services*				
18	*Other BA Losses*				
19	Rate Design Components (Provided by PFR & PTM)	$	159,343	$	705,445
20	Resource Support Services	$	42,574	$	108,570
21	Diurnal Flattening Service	$	-	$	-
22	*DFS Energy (Variable)*				
23	*DFS Capacity (Fixed)*				
24	Forced Outage Reserve	$	-	$	-
25	*Forced Outage Reserve Capacity (Fixed)*				
26	Transmission Scheduling Services	$	42,574	$	108,570
27	*Transmission Curtailment Management Service Capacity (Fixed)*				
28	*Transmission Curtailment Management Service Energy (Variable)*				
29	*Alternative Transmission Path Costs*				
30	*Generation Imbalance*				
31	*TSS - Overhead*	$	42,574	$	108,570
32	Resource Shaping Charge	$	-	$	-
33	Tier 2 Overhead	$	214,642	$	557,099
34	Risk Adder	$	-	$	-
35	Carbon Costs Passthrough	$	-	$	-
36	Renewable Energy Credits (MWh)	0		0	
37	Quantity Purchased (MWh)	193,248		484,428	
38	Tier 2 Obligation w/o losses (Billing Determinant)	185,105		472,041	
39	Tier 2 Obligation w losses	190,323		485,357	
40	Energy Short/(Long) (MWh)	-2,925		929	
41	Composite Cost Pool Augmentation (MWh)	0		1,544,244	
42	Augmentation Price ($/MWh)	$	37.78	$	42.84
43	Flat Block RSC ($/MWh)	$	33.46	$	37.87
44	Tier 2 Balancing Adjustment Debit/(Credit)	$	(97,873)	$	39,776
45					
46	Total Fixed Costs	$	8,604,281	$	22,981,774
47					
48	**Billing Components**				
49	ST.1.2012_2014 ($/MWh)	$	46.48	$	48.69
50					
51	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$	(214,642)	$	(557,099)
52	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$	-	$	-
53	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$	(42,574)	$	(108,570)
54	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$	-	$	(39,776)
55	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$	97,873	$	-
56					
57	Check	TRUE		TRUE	

Table 3.9
Tier 2 Load Growth Rate Costing Table

	B		C		D
1	**LG.1.2012_2028**				
2	**Tier2PricingModel.xls**				
3					
4	Hours		8,784		8,760
5	Notice		Nov 1, 2009		
6	Fiscal Year		FY2012		FY2013
7	Rate Period		WP-12		
8	LG.1.2012_2028				
9	**Total Forecast Expected Cost**	$	-	$	1,140,812
10	Base Power Purchase Cost (Provided by PTL)	$	-	$	1,087,466
11	Power Purchase Cost	$	-	$	1,087,466
12	Transmission	$	-	$	-
19	Rate Design Components (Provided by PFR & PTM)	$	-	$	53,346
20	Resource Support Services	$	-	$	5,396
32	Resource Shaping Charge	$	-	$	-
33	Tier 2 Overhead	$	-	$	27,686
34	Risk Adder	$	-	$	-
35	Carbon Costs Passthrough	$	-	$	-
36	Renewable Energy Credits (MWh)		0		0
37	Quantity Purchased (MWh)		0		23,652
38	Tier 2 Obligation w/o losses (Billing Determinant)		0		23,459
39	Tier 2 Obligation w losses		0		24,125
40	Energy Short/(Long) (MWh)		0		473
41	Composite Cost Pool Augmentation (MWh)		0		1,544,244
42	Augmentation Price ($/MWh)	$	37.78	$	42.84
43	Flat Block RSC ($/MWh)	$	33.46	$	37.87
44	Tier 2 Balancing Adjustment Debit/(Credit)	$	-	$	20,263
45					
46	Total Fixed Costs	$	-	$	1,140,812
47					
48	**Billing Components**				
49	LG.1.2012_2028 ($/MWh)	$	-	$	48.63
50					
51	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$	-	$	(27,686)
52	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$	-	$	-
53	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$	-	$	(5,396)
54	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$	-	$	(20,263)
55	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$	-	$	-
56					
57	Check		TRUE		TRUE

Table 3.10
Tier 2 Purchases Made by BPA

	B	C	D	E	F	G	H	I	J	K
1	Tier2Purchases									
2	Tier2PricingModel.xls									
3										
4	1	2	3	4	5	6	7	8	9	10
5	start_date	maturity_date	trade_date	internal_portfolio	tran_status	hours	price	revenue	position	choice
6	10/1/2012	9/30/2013	4/5/2010	Load Growth T2	Validated	8760	$ 46.20	$ (607,068.00)	1.50	Seller's Choice
7	10/1/2012	9/30/2013	5/24/2010	Load Growth T2	Validated	8760	$ 45.70	$ (480,398.40)	1.20	Seller's Choice
8	10/1/2012	9/30/2013	5/24/2010	ST Default Rate T2	Validated	8760	$ 45.70	$ (9,527,901.60)	23.80	Seller's Choice
9	10/1/2011	9/30/2012	4/1/2010	ST Default Rate T2	Validated	8784	$ 43.70	$ (8,444,937.60)	22.00	Seller's Choice
10	10/1/2012	9/30/2013	4/5/2010	ST Default Rate T2	Validated	8760	$ 46.20	$ (12,748,428.00)	31.50	Seller's Choice

	L	M	N	O	P	Q	R	S	T
1									
2									
3									
4	11	12	13	14	15	16	17	18	19
5	product	term	Description	reference	tran_num	buy_sell	RIS	deal_num	pt_of_receipt_loc
6	FLAT	Yearly	Energy	T2 load growth	188001	Buy	79572	187994	MID-C
7	FLAT	Yearly	Energy	Related to deal #191524	191739	Buy	79572	191735	MID-C
8	FLAT	Yearly	Energy	Related to deal #191735	191737	Buy	79571	191524	MID-C
9	FLAT	Yearly	Energy	t2 st default rate	187997	Buy	79571	187997	MID-C
10	FLAT	Yearly	Energy	T2 st default rate	187999	Buy	79571	187995	MID-C

Table 3.11
Tier 2 Load Obligation

	B	C	D	E	F	G	H
1	Tier2Obligations						
2	Tier2PricingModel.xls						
3							
4	Sorting Key	Rate Pool	Fiscal Year	aMW Quantity w/o Losses	aMW Quantity w/ Losses (1)		
5	LG.1.2012_2028_FY2012	LG.1.2012_2028	FY2012	0.000	0.000		
6	LG.1.2012_2028_FY2013	LG.1.2012_2028	FY2013	2.678	2.754		
7	LG.1.2012_2028_FY2014	LG.1.2012_2028	FY2014	*6.558*	*6.743*	(2)	
8	LG.1.2012_2028_FY2015	LG.1.2012_2028	FY2015				
9	LG.1.2012_2028_FY2016	LG.1.2012_2028	FY2016				
10	LG.1.2012_2028_FY2017	LG.1.2012_2028	FY2017				
11	LG.1.2012_2028_FY2018	LG.1.2012_2028	FY2018				
12	LG.1.2012_2028_FY2019	LG.1.2012_2028	FY2019				
13	LG.1.2012_2028_FY2020	LG.1.2012_2028	FY2020				
14	LG.1.2012_2028_FY2021	LG.1.2012_2028	FY2021				
15	LG.1.2012_2028_FY2022	LG.1.2012_2028	FY2022				
16	LG.1.2012_2028_FY2023	LG.1.2012_2028	FY2023				
17	LG.1.2012_2028_FY2024	LG.1.2012_2028	FY2024				
18	LG.1.2012_2028_FY2025	LG.1.2012_2028	FY2025				
19	LG.1.2012_2028_FY2026	LG.1.2012_2028	FY2026				
20	LG.1.2012_2028_FY2027	LG.1.2012_2028	FY2027				
21	LG.1.2012_2028_FY2028	LG.1.2012_2028	FY2028				
22	ST.1.2012_2014_FY2012	ST.1.2012_2014	FY2012	21.073	21.667		
23	ST.1.2012_2014_FY2013	ST.1.2012_2014	FY2013	53.886	55.406		
24	ST.1.2012_2014_FY2014	ST.1.2012_2014	FY2014	*40.999*	*42.155*	(2)	
25	ST.2.2015_2019_FY2015	ST.2.2015_2019	FY2015				
26	ST.2.2015_2019_FY2016	ST.2.2015_2019	FY2016				
27	ST.2.2015_2019_FY2017	ST.2.2015_2019	FY2017				
28	ST.2.2015_2019_FY2018	ST.2.2015_2019	FY2018				
29	ST.2.2015_2019_FY2019	ST.2.2015_2019	FY2019				
30	ST.3.2020_2024_FY2020	ST.3.2020_2024	FY2020				
31	ST.3.2020_2024_FY2021	ST.3.2020_2024	FY2021				
32	ST.3.2020_2024_FY2022	ST.3.2020_2024	FY2022				
33	ST.3.2020_2024_FY2023	ST.3.2020_2024	FY2023				
34	ST.3.2020_2024_FY2024	ST.3.2020_2024	FY2024				
35	ST.4.2025_2028_FY2025	ST.4.2025_2028	FY2025				
36	ST.4.2025_2028_FY2026	ST.4.2025_2028	FY2026				
37	ST.4.2025_2028_FY2027	ST.4.2025_2028	FY2027				
38	ST.4.2025_2028_FY2028	ST.4.2025_2028	FY2028				
39	V.1.20XX_20XX_FY20XX	V.1.20XX_20XX	FY20XX				
40	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
41	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
42	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
43	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
44	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
45	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
46	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
47	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
48	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
49	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
50	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
51	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
52	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
53	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
54	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
55	V.X.20XX_20XX_FY20XX	V.X.20XX_20XX	FY20XX				
56							
57	*Notes*						
58	(1) Baed on a losses factor of 2.82%						
59	(2) Based on estimates of A-HWM load for FY 2014. Actual A-RHWM load for FY 2014 shall be calculated as per the TRM.						

Table 3.12
Fixed Irrigation Rate Mitigation Program Percentage

IRMP Discount Calculation for TRM		
Step 1: Calculate Current Discount %		
FY2009 IRMP Revenues @ IRMP Rates		**$20,442,456**
FY2009 IRMP Revenues @ PF Rates (LDD adjusted)		**$32,480,256**
TRM IRMP %	**37.06%**	(1-IRMP$/PF$)

Notes:

1/ The FY2009 IRMP rates in columns S through V are corrected for the errors found in the calculations of the Load Following and Slice/Block customers' IRMP rates. The original rates gave Slice/Block customer's higher benefits than intended and Load Following customer's lower benefits than intended.

2/ The FY2009 IRMP savings in column AI ($12,037,800) do not exactly match the corrected savings amounts shared with customers during the correction process ($12,025,532). The savings amounts of $12,025, 532 were calculated using FY2007 LDD percents. The IRMP revenues and savings calculated in this spreadsheet are using FY2009 LDD percents. Six customers had differing LDD percents between FY2007 and FY2009.

Table 3.13
FY2009 Irrigation Rate Mitigation Program Data

	A	B	C	D	E	F	G	H	I	J	K	L	M
				HLH May	HLH June	HLH July	HLH August	LLH May	LLH June	LLH July	LLH August	FY09 LDD	HLH LLH Slice/LF -
1	Cus250	Klickitat	10231	2417991	3245215	4373674	3591740	1420090	1905920	2568665	2109434	7.0%	LF
2	Cus311	United	10391	3867327	7924630	9364500	6733739	2271288	4654148	5499786	3954735	3.0%	LF
3	Cus318	Columbia Basin	10109	3119657	4077069	3364323	2732162	1832180	2394469	1975873	1604603	7.0%	LF
4	Cus321	Columbia Power	10111	513090	629339	1111094	1039894	301339	369612	652548	610732	7.0%	LF
5	Cus341	Harney	10197	14017365	14449558	18671258	15798318	8232420	8486249	10965660	9278378	7.0%	LF
6	Cus348	Inland	10209	8360686	11165603	9510672	8834041	4910244	6557576	5585633	5188247	7.0%	LF
7	Cus361	Midstate	10256	5360793	6163575	7833858	6780042	3148402	3619877	4600837	3981930	7.0%	LF
8	Cus367	Nespelem	10273	937199	1370133	1939127	1752416	550419	804681	1138852	1029197	7.0%	LF
9	Cus371	OTEC	10291	3530616	5825492	7544409	5943661	2073537	3421321	4430844	3490721	6.0%	LF
10	Cus386	Surprise Valley	10369	4872445	6833839	8609055	8797529	2861595	4013524	5056112	5166802	7.0%	LF
11	Cus394	Wasco	10442	1449715	1617769	1704961	1359553	851420	950118	1001326	798467	7.0%	LF
12	Cus396	Wells	10446	606555	1230733	1381788	1298868	356230	722811	811527	762828	5.5%	LF
13	Cus482	USBIA Wapato	10399	1207762	970779	1014128	1336840	709320	570140	595599	785129	0.0%	LF
14	Cus388	Umatilla	10298	28813786	36288000	36560160	34216560	16922382	21312000	21471840	20095440	5.5%	Slice
15	Cus384	Salmon River	10298	912174	1938404	1929783	1838205	535722	1138428	1133364	1079580	5.5%	Slice
16	Cus359	Lost River	10298	1406160	2268000	2812320	2343600	825840	1332000	1651680	1376400	6.5%	Slice
17	Cus337	Fall River	10298	474256	5896800	9374400	5931388	278531	3463200	5505600	3483513	6.5%	Slice
18	Cus312	Central Elec	10298	3676945	6805555	7482792	7918544	2159476	3996914	4394656	4650574	7.0%	Slice
19	Cus303	Benton REA	10025	7942509	13310728	17300688	13673615	4664648	7817412	10160721	8030535	6.5%	LF
20	Cus266	Okanogan PUD	10286	5558396	8056671	10780560	9935516	3264454	4731695	6331440	5835144	0.0%	Slice
21	Cus203	Benton PUD	10024	37288265	52822590	62482600	44117240	21899458	31022791	36696130	25910125	0.0%	Slice
22	Cus233	Franklin PUD	10183	9516251	16653438	17248204	16058672	5588909	9780591	10129897	9431284	0.0%	Slice
23	Cus379	Raft River	10298	11718000	13154400	17342640	13124160	6882000	7725600	10185360	7707840	7.0%	Slice
24	Cus306	BigBend	10027	23849153	35626185	37412550	35203922	14006645	20923315	21972450	20675319	7.0%	LF
25	Cus335	EastEnd	10142	799377	1019171	934119	882108	469476	598561	548609	518064	3.0%	LF
26	Cus381	Riverside	10338	385249	719676	851612	661246	226257	422667	500153	388351	3.5%	LF
27	Cus385	Southside	10360	1591383	3962861	3849102	3202538	934622	2327394	2260584	1880855	3.5%	LF
28	Cus324	Columbia REA	10113	15297558	22186654	26170502	21178541	8984280	13030257	15369977	12438191	7.0%	LF

Table 3.13
FY2009 Irrigation Rate Mitigation Program Data (continued)

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
			20.50	18.55	22.85	26.76								20.5	18.55	22.85	26.76		
			14.17	9.85	16.73	19.85								14.17	9.85	16.73	19.85		
			NEW Contract RATES 1/					New Charges						PFCharges					
			200905	200906	200907	200908													
			May	June	July	Aug	CUS No	May	June	July	August	TOTAL		May	Jun	Jul	Aug	TOTAL	Savings 2/
1	Cus250	Klickitat	10.00	7.37	12.25	15.62	250	$ 38,381	$ 37,964	$ 85,044	$ 89,052	$ 250,441		$ 64,813	$ 73,444	$ 132,908	$ 128,328	$ 399,494	$ (149,053)
2	Cus311	United	10.05	7.32	12.40	15.89	311	$ 61,693	$ 92,077	$ 184,317	$ 169,840	$ 507,927		$ 108,120	$ 187,060	$ 296,811	$ 250,935	$ 842,926	$ (335,000)
3	Cus318	Columbia Basin	10.24	7.61	12.49	15.86	318	$ 50,707	$ 49,248	$ 66,699	$ 68,781	$ 235,435		$ 83,621	$ 92,270	$ 102,236	$ 97,617	$ 375,744	$ (140,308)
4	Cus321	Columbia Power	9.54	6.91	11.79	15.16	321	$ 7,770	$ 6,903	$ 20,793	$ 25,023	$ 60,489		$ 13,753	$ 14,243	$ 33,764	$ 37,154	$ 98,914	$ (38,425)
5	Cus341	Harney	10.03	7.40	12.28	15.65	341	$ 223,165	$ 169,725	$ 363,941	$ 392,450	$ 1,149,282		$ 375,729	$ 327,015	$ 567,387	$ 564,453	$ 1,834,584	$ (685,302)
6	Cus348	Inland	10.11	7.48	12.36	15.73	348	$ 134,169	$ 132,569	$ 186,590	$ 220,571	$ 673,899		$ 224,104	$ 252,694	$ 289,013	$ 315,629	$ 1,081,440	$ (407,540)
7	Cus361	Midstate	10.29	7.66	12.54	15.91	361	$ 87,560	$ 74,941	$ 155,931	$ 171,223	$ 489,655		$ 143,693	$ 139,491	$ 238,057	$ 242,242	$ 763,484	$ (273,829)
8	Cus367	Nespelem	9.99	7.36	12.24	15.61	367	$ 14,861	$ 16,007	$ 37,674	$ 43,421	$ 111,963		$ 25,121	$ 31,008	$ 58,927	$ 62,612	$ 177,668	$ (65,704)
9	Cus371	OTEC	10.45	7.79	12.73	16.13	371	$ 58,563	$ 72,033	$ 152,445	$ 152,177	$ 435,218		$ 95,654	$ 133,257	$ 231,727	$ 214,643	$ 675,280	$ (240,063)
10	Cus386	Surprise Valley	9.75	7.12	12.00	15.37	386	$ 75,407	$ 77,233	$ 163,982	$ 214,632	$ 531,254		$ 130,604	$ 154,660	$ 261,614	$ 314,324	$ 861,202	$ (329,948)
11	Cus394	Wasco	10.53	7.90	12.78	16.15	394	$ 24,231	$ 20,286	$ 34,586	$ 34,852	$ 113,956		$ 38,859	$ 36,612	$ 51,811	$ 48,575	$ 175,857	$ (61,902)
12	Cus396	Wells	9.82	7.16	12.10	15.50	396	$ 9,455	$ 13,987	$ 26,539	$ 31,956	$ 81,937		$ 16,521	$ 28,303	$ 42,667	$ 47,155	$ 134,646	$ (52,709)
13	Cus482	USBIA Wapato	11.04	8.21	13.47	17.08	482	$ 21,165	$ 12,651	$ 21,683	$ 36,243	$ 91,742		$ 34,810	$ 23,624	$ 33,137	$ 51,359	$ 142,930	$ (51,188)
14	Cus388	Umatilla	10.45	7.78	12.74	16.16	388	$ 477,943	$ 448,128	$ 739,328	$ 877,682	$ 2,543,081		$ 784,797	$ 834,497	$ 1,128,919	$ 1,242,230	$ 3,990,444	$ (1,447,363)
15	Cus384	Salmon River	11.66	8.98	13.95	17.37	384	$ 16,882	$ 27,630	$ 42,731	$ 50,682	$ 137,925		$ 24,845	$ 44,577	$ 59,589	$ 66,736	$ 195,746	$ (57,821)
16	Cus359	Lost River	7.47	4.84	9.72	13.09	359	$ 16,673	$ 17,424	$ 43,390	$ 48,695	$ 126,182		$ 37,894	$ 51,604	$ 85,921	$ 84,184	$ 259,603	$ (133,421)
17	Cus337	Fall River	8.96	6.33	11.21	14.59	337	$ 6,745	$ 59,249	$ 166,805	$ 137,363	$ 370,162		$ 12,781	$ 134,171	$ 286,403	$ 213,060	$ 646,415	$ (276,253)
18	Cus312	Central Elec	10.02	7.39	12.27	15.64	312	$ 58,481	$ 79,830	$ 145,736	$ 196,581	$ 480,628		$ 98,559	$ 154,020	$ 227,389	$ 282,919	$ 762,887	$ (282,258)
19	Cus303	Benton REA	9.87	7.22	12.14	15.52	303	$ 124,433	$ 152,545	$ 333,382	$ 336,848	$ 947,208		$ 214,040	$ 302,861	$ 528,564	$ 491,167	$ 1,536,632	$ (589,424)
20	Cus266	Okanogan PUD	11.77	8.94	14.20	17.81	266	$ 103,845	$ 114,328	$ 242,990	$ 280,875	$ 742,039		$ 160,204	$ 196,058	$ 352,261	$ 381,702	$ 1,090,226	$ (348,187)
21	Cus203	Benton PUD	11.59	8.75	14.01	17.62	203	$ 685,986	$ 733,647	$ 1,389,494	$ 1,233,882	$ 4,043,009		$ 1,074,725	$ 1,285,434	$ 2,041,654	$ 1,694,893	$ 6,096,705	$ (2,053,696)
22	Cus233	Franklin PUD	10.93	8.09	13.36	16.96	233	$ 165,099	$ 213,851	$ 365,771	$ 432,310	$ 1,177,032		$ 274,278	$ 405,260	$ 563,595	$ 616,941	$ 1,860,074	$ (683,042)
23	Cus379	Raft River	9.25	6.61	11.50	14.87	379	$ 172,050	$ 138,017	$ 316,572	$ 309,772	$ 936,411		$ 314,095	$ 297,703	$ 527,013	$ 468,909	$ 1,607,721	$ (671,310)
24	Cus306	BigBend	9.74	7.11	11.99	15.36	306	$ 368,715	$ 402,067	$ 712,026	$ 858,305	$ 2,341,114		$ 639,265	$ 806,273	$ 1,136,903	$ 1,257,790	$ 3,840,230	$ (1,499,117)
25	Cus335	EastEnd	10.95	8.21	13.31	16.82	335	$ 13,894	$ 13,282	$ 19,735	$ 23,551	$ 70,462		$ 22,349	$ 24,057	$ 29,607	$ 32,872	$ 108,885	$ (38,424)
26	Cus381	Riverside	9.97	7.26	12.30	15.78	381	$ 6,097	$ 8,293	$ 16,627	$ 16,563	$ 47,579		$ 10,715	$ 16,900	$ 26,853	$ 24,515	$ 78,983	$ (31,403)
27	Cus385	Southside	9.77	7.06	12.10	15.58	385	$ 24,679	$ 44,409	$ 73,927	$ 79,199	$ 222,215		$ 44,262	$ 93,061	$ 121,370	$ 118,729	$ 377,420	$ (155,206)
28	Cus324	Columbia REA	9.91	7.28	12.16	15.53	324	$ 240,633	$ 256,379	$ 505,132	$ 522,068	$ 1,524,212		$ 410,044	$ 502,117	$ 795,276	$ 756,681	$ 2,464,118	$ (939,906)
												$ 20,442,456						$ 32,480,256	$ (12,037,800)

Table 3.14
Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	F	G	H	I	J	K
1											
2				Monthly Irrigation Rate Mitigation Amounts for Exhibit D of the Region Dialogue Contracts (in MWh)							
3				May	June	July	August	September	TOTAL	LDD	
4	203	10024	Benton PUD	53115.401	75243.324	89003.560	62842.958	32033.957	312239.200	0.00%	0
5	233	10183	Franklin PUD	13084.284	22897.496	23715.264	22079.728	12630.475	94407.247	0.00%	0
6	250	10231	Klickitat	3082.499	4137.060	5575.639	4578.816	4258.715	21632.729	7.00%	1514.291
7	266	10286	Okanogan PUD	7203.742	10441.534	14718.217	12876.538	10168.120	55408.151	0.00%	0
8	303	10025	Benton REA	11147.270	18681.537	24281.424	19190.846	9599.780	82900.857	6.50%	5388.556
9	306	10027	Big Bend	32097.789	47948.108	50352.318	47379.798	31891.527	209669.540	7.00%	14676.87
10	311	10391	United	5273.820	10806.706	12770.236	9182.704	6236.687	44270.153	3.50%	1549.455
11	312	10046	Central Elec	4687.388	8675.756	9539.100	10094.599	8088.614	41085.457	7.00%	2875.982
12	318	10109	Columbia Basin	4185.302	5469.756	4513.543	3665.441	3266.293	21100.335	7.00%	1477.023
13	321	10111	Columbia Power	706.641	866.742	1530.227	1432.169	691.870	5227.649	7.00%	365.9354
14	324	10113	Columbia REA	21258.914	30832.646	36368.973	29431.678	16763.751	134655.962	7.00%	9425.917
15	337	10173	Fall River	721.884	12605.402	20135.316	9028.407	1818.987	44309.996	7.00%	3101.7
16	341	10197	Harney	19540.495	20142.982	26028.119	22023.182	12164.427	99899.205	7.00%	6992.944
17	348	10209	Inland	10963.601	14641.767	12471.610	11584.325	10451.398	60112.701	7.00%	4207.889
18	359	10242	Lost River	3725.641	9902.214	10705.288	8479.424	4746.327	37558.894	6.50%	2441.328
19	361	10256	Midstate	7679.733	8829.777	11222.582	9712.913	4044.309	41489.314	7.00%	2904.252
20	367	10273	Nespelem	1216.565	1778.549	2517.152	2274.786	1734.973	9522.025	7.00%	666.5418
21	371	10291	OTEC	4715.415	7780.401	10076.149	7938.224	5750.412	36260.601	6.00%	2175.636
22	379	10331	Raft River	23443.131	30794.718	32636.209	27344.114	18868.686	133086.858	7.00%	9316.08
23	335	10142	East End	1061.340	1353.162	1240.237	1171.183	943.562	5769.484	3.00%	173.0845
24	381	10338	Riverside	528.123	986.578	1167.444	906.478	566.587	4155.210	3.00%	124.6563
25	385	10360	Southside	2180.245	5429.243	5273.390	4387.577	2738.885	20009.340	4.00%	800.3736
26	384	10343	Salmon River	1257.157	2671.504	2659.622	2533.409	1383.969	10505.661	5.00%	525.2831
27	386	10369	Surprise Valley	6464.252	9066.424	11421.596	11671.642	7586.987	46210.901	7.00%	3234.763
28	388	10388	Umatilla	39288.078	52679.345	55478.176	49073.469	32253.359	228772.427	6.00%	13726.35
29	394	10442	Wasco	1883.529	2101.872	2215.155	1766.387	1766.387	9733.330	7.00%	681.3331
30	396	10446	Wells	846.538	1717.671	1928.492	1812.765	865.874	7171.340	5.50%	394.4237
31	482	10399	USBIA Wapato	1463.062	1175.985	1228.497	1619.426	1702.727	7189.697	0.00%	0
32	390	10436	Vigilante	5362.005	10090.787	11936.481	8014.268	3459.717	38863.258	7.00%	2720.428
33	483	10258	Mission Valley	1857.275	3714.55	6500.462	5571.825	742.91	18387.022	6.50%	1195.156
34									Wt. LDD	4.9%	

Table 3.15
Sample RSS Resource Output Data

	B C D E	F	H	J
1	Resource Profiles			
2	RSSModel.PublicExample.xls			
3				
4	Key	10001	10003	10005
5	Resource Output Data Year	FY2009	FY2009	FY2009
6	Model Identifier	NF.1.Wind.1.2012_2028	NF.3.BioMass.1.2012_2014	NF.5.Solar.1.2012_2014
7	Purchaser	Tier 1	Example Customer B	Example Customer D
8	BSP	BPA	80001	80003
9	Resource Name	BreezyWind	WoodyWood	SunnySun
10	*Annual Generation aMW*	16.572	7.720	27.482
11	*Diurnal Flattening Service*	Yes	Yes	Yes
12	*Forced Outage Reserve Service*	No	Yes	No
13	*Forced Outage Rating*	*0%*	*7%*	*0%*
14	*Secondary Crediting Service*	No	No	No
15	*Grandfathered GMS*	No	No	No
16	*Services & RSC*	*DFS TSS TCMS RSC*	*DFS FOR TSS TCMS RSC*	*DFS RSC*
17				
18	Planned Outage Replacement (yes or no)	No	No	No
19	Total Planned Outage Hours	*0*	*0*	*0*
20	*Planned Outage HLH Hours*	*0*	*0*	*0*
33	*Planned Outage LLH Hours*	*0*	*0*	*0*
46				
47	*Operating/Firm Capacity kW Adjustment*	No	No	No
60				
61	*Transmission Scheduling Services*	Yes	Yes	No
62	*Transmission Curtailment Management Servi*	Yes	Yes	No
63				
64	*Apply RSC within ExhA/Tier2Obl/SCS/GMS/T*	No	No	No

Table 3.15
Sample RSS Resource Output Data (continued)

	B C D E	F	H	J
1	**Resource Profiles**			
2	**RSSModel.PublicExample.xls**			
3				
4	Key	10001	10003	10005
5	**Resource Output Data Year**	FY2009	FY2009	FY2009
6	**Model Identifier**	NF.1.Wind.1.2012_2028	NF.3.BioMass.1.2012_2014	NF.5.Solar.1.2012_2014
7	**Purchaser**	Tier 1	Example Customer B	Example Customer D
8	**BSP**	BPA	80001	80003
9	**Resource Name**	BreezyWind	WoodyWood	SunnySun
65				
66	*Exhibit A Amounts or Tier 2 Obligations Amounts*			
67	*FY2012*			
68	*Annual aMW*	*16.565*	*7.696*	*27.450*
69	*HLH MWh*	*78,031*	*37,900*	*203,949*
70	October	9,651	3,571	6,173
71	November	6,573	1,691	10,642
72	December	6,265	2,497	18,406
73	January	5,858	3,471	22,073
74	February	2,595	3,363	20,097
75	March	3,943	3,520	25,909
76	April	4,120	3,603	26,914
77	May	6,118	2,235	23,045
78	June	7,839	3,663	21,054
79	July	7,161	3,549	13,639
80	August	10,883	3,284	9,003
81	September	7,024	3,452	6,995
82	*LLH MWh*	*67,476*	*29,703*	*37,176*
83	October	6,313	2,610	508
84	November	6,543	1,340	2,113
85	December	5,380	1,954	3,606
86	January	4,861	2,840	4,117
87	February	1,722	2,512	3,732
88	March	3,318	2,839	5,230
89	April	2,570	2,657	3,657
90	May	5,748	1,942	4,783
91	June	5,367	2,708	3,167
92	July	8,591	2,812	2,781
93	August	8,704	2,699	2,255
94	September	8,360	2,792	1,228
95				
96	*FY2013*			
97	*Annual aMW*	*16.610*	*7.717*	*27.526*
98	*HLH MWh*	*78,031*	*37,900*	*203,949*
99	October	9,651	3,571	6,173
100	November	6,573	1,691	10,642
101	December	6,265	2,497	18,406
102	January	5,858	3,471	22,073
103	February	2,595	3,363	20,097
104	March	3,943	3,520	25,909
105	April	4,120	3,603	26,914
106	May	6,118	2,235	23,045
107	June	7,839	3,663	21,054
108	July	7,161	3,549	13,639
109	August	10,883	3,284	9,003
110	September	7,024	3,452	6,995
111	*LLH MWh*	*67,476*	*29,703*	*37,176*
112	October	6,313	2,610	508
113	November	6,543	1,340	2,113
114	December	5,380	1,954	3,606
115	January	4,861	2,840	4,117
116	February	1,722	2,512	3,732
117	March	3,318	2,839	5,230
118	April	2,570	2,657	3,657
119	May	5,748	1,942	4,783
120	June	5,367	2,708	3,167
121	July	8,591	2,812	2,781
122	August	8,704	2,699	2,255
123	September	8,360	2,792	1,228
124				
125	*Applicable Year(s)*	FY2012&FY2013	FY2012&FY2013	FY2012&FY2013

Table 3.16
Rates and Charges for RSS and Related Services Applied to Sample Resources

	B	C	D	E	F	G	H	I
1	RSSRates&RevenuesOutput							
2	RSSModel.PublicExample.xls							
3	Click to Calculate							
4	RSS Model Identifier	BSP	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"ResourceInput" Tab Adj. for Schedule Annual aMW	Total Planned Energy Annual aMW
5	NF.1.Wind.1.2012_2028	BPA	Tier 1	BreezyWind	DFS TSS TCMS RSC	FY2012&FY2013	16.610	16.610
7	NF.3.BioMass.1.2012_2014	80001	Example Customer B	WoodyWood	DFS FOR TSS TCMS RSC	FY2012&FY2013	7.717	7.717
9	NF.5.Solar.1.2012_2014	80003	Example Customer D	SunnySun	DFS RSC	FY2012&FY2013	27.526	27.526

	B	C	J	K	M	O	Q	S	U	W	Y	Z	AA	AB	AC
1	RSSRates&RevenuesOutput														
2	RSSModel.PublicExample.xls														
3	Click to Calculate														
4	RSS Model Identifier	BSP	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	RSC $/mo	FOR Capacity Charge $/mo	TSS $/mo	TCMS $/mo	SCS $/mo	GMS $/mo	Revenue Credit to Composite Cost Pool FY 2012	Revenue Credit to Non-Slice Cost Pool FY2012	Revenue Credit to Composite Cost Pool FY 2013	Revenue Credit to Non-Slice Cost Pool FY2013	Forecast Total $/MWh Equivalent Rate
5	NF.1.Wind.1.2012_2028	BPA	$ 3.86	$ 152,951	$ 1,482	$ -	$ 1,080	$ -	$ -	$ -	$ 2,409,381	$ 17,780	$ 2,409,381	$ 17,780	$ 16.68
7	NF.3.BioMass.1.2012_2014	80001	$ 0.19	$ 19,469	$ (9,975)	$ 3,838.00	$ 1,080	$ -	$ -	$ -	$ 305,325	$ (119,706)	$ 305,325	$ (119,706)	$ 2.75
9	NF.5.Solar.1.2012_2014	80003	$ 4.78	$ 264,889	$ (42,127)	$ -	$ -	$ -	$ -	$ -	$ 4,332,209	$ (505,523)	$ 4,332,209	$ (505,523)	$ 15.86

Table 3.17
Solar Resource DFS Example

	B	C	D	E	F	G	H	I	J	K	L
1	RSSRateCalculator										
2	RSSModel.PublicExample.xls										
3	Key		10005								
4	Resource Output Data Year		FY2009				Diurnal Flattening Service	Yes			
5	Model Identifier		NF.5.Solar.1.2012_2014								
6	BSP		80003								
7	Purchaser		Example Customer D								
8	Resource Name		SunnySun								
9	Services & RSC		DFS RSC								
10	Applicable Year(s)		FY2012&FY2013				DFS Energy		DFS Capacity		
11	Month	HLH Hours 2012	LLH Hours 2012	HLH Hours 2013	LLH Hours 2013		Cost @ 25% Losses HLH	Cost @ 25% Losses LLH	Firm Capacity (kW)	Monthly Demand Rates	Monthly Capacity Costs
12	October	416	328	432	312		$ 38,087	$ 3,596	-	$ 9.18	$ 131,173
13	November	400	321	400	321		$ 56,644	$ 14,044	-	$ 9.31	$ 258,007
14	December	416	328	400	344		$ 94,314	$ 25,176	-	$ 9.97	$ 441,125
15	January	400	344	416	328		$ 95,832	$ 25,550	-	$ 9.70	$ 514,686
16	February	400	296	384	288		$ 88,173	$ 23,990	-	$ 9.92	$ 519,175
17	March	432	311	416	327		$ 98,163	$ 33,316	-	$ 9.60	$ 597,898
18	April	400	320	416	304		$ 94,726	$ 23,271	-	$ 9.10	$ 588,749
19	May	416	328	416	328		$ 83,232	$ 23,430	-	$ 8.50	$ 489,708
20	June	416	304	400	320		$ 85,950	$ 15,797	-	$ 8.72	$ 441,314
21	July	400	344	416	328		$ 77,346	$ 17,939	-	$ 10.20	$ 334,416
22	August	432	312	432	312		$ 60,316	$ 15,914	-	$ 10.75	$ 232,643
23	September	384	336	384	336		$ 49,555	$ 9,178	-	$ 10.53	$ 184,140
24			8784		8760		Forecast Annual Revenue	$ 1,153,541		Monthly Look	$ 4,733,033
25							FY2012 Forecast Revenue	$ 1,153,541		Yearly Look	$ 3,178,664
26							FY2013 Forecast Revenue	$ 1,153,541		Min of Mo/Yr Look	$ 3,178,664
27							DFS Energy Rate $/MWh	$ 4.78		FY2012 Revenue	$ 3,178,668
28										FY2013 Revenue	$ 3,178,668
29										$/MWh Equivalent	$ 13.18
30										DFS Capacity Charge $/mo	$ 264,889

Table 3.18
Solar Resource RSC Example

	T	U	V	W
10	Resource Shaping Charge			
11	HLH FY2012	LLH FY2012	HLH FY2013	LLH FY2013
12	$ 198,633	$ 265,062	$ 216,492	$ 252,091
13	$ 12,986	$ 210,342	$ 14,140	$ 211,100
14	$ (287,150)	$ 180,238	$ (303,965)	$ 195,767
15	$ (444,050)	$ 168,836	$ (425,216)	$ 155,695
16	$ (373,155)	$ 145,721	$ (389,949)	$ 139,155
17	$ (555,971)	$ 106,908	$ (572,112)	$ 121,903
18	$ (598,004)	$ 155,931	$ (580,347)	$ 143,270
19	$ (407,597)	$ 102,993	$ (406,500)	$ 103,595
20	$ (346,540)	$ 119,195	$ (361,256)	$ 129,859
21	$ (111,853)	$ 199,260	$ (92,059)	$ 186,861
22	$ 126,657	$ 202,865	$ 128,098	$ 203,620
23	$ 154,078	$ 268,573	$ 155,333	$ 269,422
24				$ (1,011,045)
25			FY2012 Forecast Revenue	$ (505,523)
26			FY2013 Forecast Revenue	$ (505,523)
27			$/MWh Equivalent	$ (2.10)
28			RSC $/mo	$ (42,127)

Table 3.19
Biomass Resource DFS Example

	B	C	D	E	F	G	H	I	J	K	L
1	RSSRateCalculator										
2	**RSSModel.PublicExample.xls**										
3	Key		10005								
4	Resource Output Data Year		FY2009				Diurnal Flattening Service	Yes			
5	Model Identifier		NF.3.BioMass.1.2012_2014								
6	BSP		80001								
7	Purchaser		Example Customer B								
8	Resource Name		WoodyWood								
9	Services & RSC		DFS FOR TSS TCMS RSC								
10	Applicable Year(s)		FY2012&FY2013				DFS Energy		DFS Capacity		
11	Month	HLH Hours 2012	LLH Hours 2012	HLH Hours 2013	LLH Hours 2013		Cost @ 25% Losses HLH	Cost @ 25% Losses LLH	Firm Capacity (kW)	Monthly Demand Rates	Monthly Capacity Costs
12	October	416	328	432	312		$ 1,694	$ 827	5,575	$ 9.18	$ 24,714
13	November	400	321	400	321		$ 1,794	$ 1,068	-	$ 9.31	$ 40,999
14	December	416	328	400	344		$ 288	$ 192	5,781	$ 9.97	$ 2,209
15	January	400	344	416	328		$ 420	$ 87	8,156	$ 9.70	$ 1,829
16	February	400	296	384	288		$ 399	$ 274	8,295	$ 9.92	$ 4,600
17	March	432	311	416	327		$ 554	$ 339	8,144	$ 9.60	$ 3,050
18	April	400	320	416	304		$ 347	$ 167	8,320	$ 9.10	$ 3,117
19	May	416	328	416	328		$ 368	$ 177	-	$ 8.50	$ 47,498
20	June	416	304	400	320		$ 432	$ 86	8,436	$ 8.72	$ 3,228
21	July	400	344	416	328		$ 1,031	$ 531	7,278	$ 10.20	$ 12,770
22	August	432	312	432	312		$ 643	$ 241	-	$ 10.75	$ 84,853
23	September	384	336	384	336		$ 500	$ 218	8,178	$ 10.53	$ 4,762
24			8784		8760		Forecast Annual Revenue	$ 12,677		Monthly Look	$ 233,631
25							FY2012 Forecast Revenue	$ 12,677		Yearly Look	$ 891,191
26							FY2013 Forecast Revenue	$ 12,677		Min of Mo/Yr Look	$ 233,631
27							DFS Energy Rate $/MWh	$ 0.19		FY2012 Revenue	$ 233,628
28										FY2013 Revenue	$ 233,628
29										$/MWh Equivalent	$ 3.46
30										DFS Capacity Charge $/mo	$ 19,469
31											

Table 3.20
Biomass Resource RSC, FORS, and TSS Example

	T	U	V	W	X	Y	Z	AA	AB	AC	AD
4						FOR Service	Yes			TSS	Yes
5						FOR Rating	7%				
6											
7											
8											
9											
10	Resource Shaping Charge					FOR Capacity				TSS	
11	HLH FY2012	LLH FY2012	HLH FY2013	LLH FY2013		FY2012 Monthly Reservation Costs	FY2013 Monthly Reservation Costs	FORE Limits (MWh)		$/MWh Rate	$/mo
12	$ (14,000)	$ (2,671)	$ (8,993)	$ (6,308)		$ 3,582	$ 3,582	433		$ 0.23	$ 1,080
13	$ 47,935	$ 29,835	$ 48,258	$ 30,047		$ -	$ -	234	FY2012	$ 15,549	$ 12,960
14	$ 28,964	$ 18,861	$ 24,249	$ 23,214		$ 4,034	$ 4,034	312	FY2013	$ 15,549	$ 12,960
15	$ (23,107)	$ (8,363)	$ (17,827)	$ (12,047)		$ 5,538	$ 5,538	460			$ 25,920
16	$ (11,659)	$ (8,057)	$ (16,368)	$ (9,898)		$ 5,760	$ 5,760	411		FY2012 Revenue	$ 12,960
17	$ (10,802)	$ (14,395)	$ (15,328)	$ (10,191)		$ 5,472	$ 5,472	451		FY2013 Revenue	$ 12,960
18	$ (19,702)	$ (5,900)	$ (14,751)	$ (9,450)		$ 5,300	$ 5,300	438		$/MWh Equivalent	$ 0.19
19	$ (10,199)	$ (12,176)	$ (9,891)	$ (12,007)		$ -	$ -	456		TSS Charge $/mo	$ 1,080
20	$ (16,610)	$ (8,470)	$ (20,736)	$ (5,480)		$ 5,149	$ 5,149	446			
21	$ (19,776)	$ (4,906)	$ (14,227)	$ (8,383)		$ 5,197	$ 5,197	445			
22	$ (11,553)	$ (14,602)	$ (11,149)	$ (14,390)		$ -	$ -	451			
23	$ (21,584)	$ (6,912)	$ (21,232)	$ (6,674)		$ 6,028	$ 6,028	437			
24				$ (239,411)			$ 92,121	Annual Limit			
25			FY2012 Forecast Revenue	$ (119,706)		FY2012 Revenue	$ 46,060	9,948			
26			FY2013 Forecast Revenue	$ (119,706)		FY2013 Revenue	$ 46,060	Purchase Period Limit			
27			$/MWh Equivalent	$ (1.77)		$/MWh Equivalent	$ 0.68	14,922			
28			RSC $/mo	$ (9,975)		FOR Charge $/mo	$ 3,838				
29											
30						Total FY2012 Composite Credit	$ 305,325				
31						Total FY2012 Non-Slice Credit	$ (119,706)				
32						Total Forecast FY2012 Revenue	$ 185,620				
33						Total FY2013 Composite Credit	$ 305,325				
34						Total FY2013 Non-Slice Credit	$ (119,706)				
35						Total Forecast FY2013 Revenue	$ 185,620				

Table 3.21
Wind Resource DFS Example

	B	C	D	E	F	G	H	I	J	K	L
1	RSSRateCalculator										
2	**RSSModel.PublicExample.xls**										
3		Key	10001								
4		Resource Output Data Year	FY2009				Diurnal Flattening Service	Yes			
5		Model Identifier	NF.1.Wind.1.2012_2028								
6		BSP	BPA								
7		Purchaser	Tier 1								
8		Resource Name	BreezyWind								
9		Services & RSC	DFS TSS TCMS RSC								
10		Applicable Year(s)	FY2012&FY2013				DFS Energy		DFS Capacity		
11	Month	HLH Hours 2012	LLH Hours 2012	HLH Hours 2013	LLH Hours 2013		Cost @ 25% Losses HLH	Cost @ 25% Losses LLH	Firm Capacity (kW)	Monthly Demand Rates	Monthly Capacity Costs
12	October	416	328	432	312		$ 38,589	$ 20,943	-	$ 9.18	$ 205,082
13	November	400	321	400	321		$ 30,312	$ 22,435	-	$ 9.31	$ 159,362
14	December	416	328	400	344		$ 31,770	$ 20,660	-	$ 9.97	$ 150,150
15	January	400	344	416	328		$ 30,053	$ 18,315	-	$ 9.70	$ 136,588
16	February	400	296	384	288		$ 18,623	$ 9,810	-	$ 9.92	$ 67,047
17	March	432	311	416	327		$ 23,772	$ 16,537	-	$ 9.60	$ 90,990
18	April	400	320	416	304		$ 22,602	$ 10,583	-	$ 9.10	$ 90,128
19	May	416	328	416	328		$ 25,480	$ 16,287	-	$ 8.50	$ 130,013
20	June	416	304	400	320		$ 27,499	$ 12,091	-	$ 8.72	$ 164,322
21	July	400	344	416	328		$ 35,307	$ 17,752	-	$ 10.20	$ 175,581
22	August	432	312	432	312		$ 37,564	$ 20,624	-	$ 10.75	$ 281,242
23	September	384	336	384	336		$ 33,196	$ 20,204	-	$ 10.53	$ 184,913
24			8784		8760		Forecast Annual Revenue	$ 561,009		Monthly Look	$ 1,835,418
25							FY2012 Forecast Revenue	$ 561,009		Yearly Look	$ 1,918,164
26							FY2013 Forecast Revenue	$ 561,009		Min of Mo/Yr Look	$ 1,835,418
27							DFS Energy Rate $/MWh	$ 3.86		FY2012 Revenue	$ 1,835,412
28										FY2013 Revenue	$ 1,835,412
29										$/MWh Equivalent	$ 12.61
30										DFS Capacity Charge $/mo	$ 152,951

Table 3.22
Biomass Resource RSC and TSS Example

	T	U	V	W	AB	AC	AD
3							
4						TSS	Yes
5							
6							
7							
8							
9							
10	Resource Shaping Charge					TSS	
11	HLH FY2012	LLH FY2012	HLH FY2013	LLH FY2013		$/MWh Rate	$/mo
12	$ (104,489)	$ (27,448)	$ (93,712)	$ (35,275)		$ 0.23	$ 1,080
13	$ 2,031	$ (38,493)	$ 2,728	$ (38,036)	FY2012	$ 33,467	$ 12,960
14	$ 25,728	$ 1,778	$ 15,581	$ 11,149	FY2013	$ 33,467	$ 12,960
15	$ 30,751	$ 26,546	$ 42,116	$ 18,616			$ 25,920
16	$ 164,974	$ 105,528	$ 154,839	$ 101,566		FY2012 Revenue	$ 12,960
17	$ 127,145	$ 59,293	$ 117,405	$ 68,342		FY2013 Revenue	$ 12,960
18	$ 94,044	$ 83,056	$ 104,700	$ 75,415		$/MWh Equivalent	$ 0.09
19	$ 27,094	$ (7,670)	$ 27,756	$ (7,307)		TSS Charge $/mo	$ 1,080
20	$ (34,106)	$ (7,616)	$ (42,986)	$ (1,181)			
21	$ (22,506)	$ (86,506)	$ (10,561)	$ (93,988)			
22	$ (165,307)	$ (113,669)	$ (164,438)	$ (113,214)			
23	$ (28,820)	$ (93,871)	$ (28,063)	$ (93,359)			
24				$ 35,560			
25			FY2012 Forecast Revenue	$ 17,780			
26			FY2013 Forecast Revenue	$ 17,780			
27			$/MWh Equivalent	$ 0.12			
28			RSC $/mo	$ 1,482			

Table 3.23
Rates and Charges for RSS and Related Services in FY 2012 and FY 2013

	D	E	F	G	H	I
1						
2						
3						
4	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"ResourceIn put" Tab Adj. for Schedule Annual aMW	Total Planned Energy Annual aMW
5	NO WASCO	McNary Fishway	GMS	FY2012&FY2013	N/A	N/A
6	CENTRALIA	Yelm Hydro	GMS	FY2012&FY2013	N/A	N/A
7	BONNERS FY	Moyie	GMS	FY2012&FY2013	N/A	N/A
8	MCMINNV	Priest&Wanapum	SCS	FY2012&FY2013	N/A	N/A
9	FOREST GRV	Priest&Wanapum	SCS	FY2012&FY2013	N/A	N/A
10	KITTITAS P	Priest&Wanapum	SCS	FY2012&FY2013	N/A	N/A
11	MILTON-FREEWATER	Priest&Wanapum	SCS	FY2012&FY2013	N/A	N/A
12	PNGC	Island Park Hydro Resource	SCS	FY2012&FY2013	N/A	N/A
13	PNGC	Lake Creek Hydro Resource	SCS	FY2012&FY2013	N/A	N/A
14	MASON PUD3	Packwood	SCS TSS TCMS	FY2012&FY2013	N/A	N/A
15	Tier 1	Klondike III	DFS TSS TCMS RSC	FY2012&FY2013	13.968	13.968
16	CLALLAM PUD	Packwood	DFS FOR TSS TCMS RSC	FY2012&FY2013	1.075	1.075
17	MASON PUD3	Nine Canyon I, II & III	DFS TSS TCMS RSC	FY2012&FY2013	0.821	0.821
18	PNGC	Coffin Butte 2	DFS FOR RSC	FY2012&FY2013	3.046	3.046
19	FLATHEAD	Landfill Gas To Energy Project	DFS FOR RSC	FY2012&FY2013	0.793	0.793
20	MISSION VALLEY	Kerr Dam	TSS TCMS	FY2012&FY2013	N/A	N/A
21	BENTON REA	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
22	BIG BEND	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
23	INLAND	Unspecified	TSS TCMS	FY2013	N/A	N/A
24	IDAHO LIGHT & POWER	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
25	VERA ID	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
26	LOWER VALLEY	Unspecified	TSS TCMS	FY2013	N/A	N/A
27	WELLS REC	Unspecified	TSS TCMS	FY2013	N/A	N/A
28	CHENEY	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
29	CENTRAL LINCOLN PUD	Unspecified	TSS TCMS	FY2013	N/A	N/A
30	CENTRALIA	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
31	UNITED EC	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
32	COULUMBIA REA	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
33	RICHLAND	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A
34	PENINSULA	Unspecified	TSS TCMS	FY2012&FY2013	N/A	N/A

Table 3.23
Rates and Charges for RSS and Related Services in FY 2012 and FY 2013 (continued)

	D	J	K	M	N	O	Q	S	U	W	X	Y	Z	AA	AB	AC
1																
2																
3																
4	Purchaser	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	TSS $/mo	TCMS $/mo	SCS $/mo	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY 2012	Revenue Credit to Non-Slice Cost Pool FY2012	Revenue Credit to Composite Cost Pool FY 2013	Revenue Credit to Non-Slice Cost Pool FY2013	Forecast Total $/MWh Equivalent Rate
5	NO WASCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,120	$ 0.66	$ 25,446	$ -	$ 25,446	$ -	$ 0.66
6	CENTRALIA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,424	$ 0.66	$ 41,093	$ -	$ 41,093	$ -	$ 0.66
7	BONNERS FY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 874	$ 0.64	$ 10,485	$ -	$ 10,485	$ -	$ 0.64
8	MCMINNV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,322	$ -	$ -	$ 15,864	$ -	$ 15,864	$ -	$ 0.62
9	FOREST GRV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,322	$ -	$ -	$ 15,864	$ -	$ 15,864	$ -	$ 0.62
10	KITTITAS P	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 441	$ -	$ -	$ 5,288	$ -	$ 5,288	$ -	$ 0.62
11	MILTON-FREEWATER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,322	$ -	$ -	$ 15,864	$ -	$ 15,864	$ -	$ 0.62
12	PNGC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 473	$ -	$ -	$ 5,670	$ -	$ 5,670	$ -	$ 0.65
13	PNGC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 702	$ -	$ -	$ 8,419	$ -	$ 8,419	$ -	$ 0.63
14	MASON PUD3	$ -	$ -	$ -	$ -	$ -	$ 110	$ -	$ 310	$ -	$ -	$ 5,049	$ -	$ 5,049	$ -	$ 0.88
15	Tier 1	$ 3.59	$ 130,276	$ 60,397	$ 5.92	$ -	$ 1,080	$ -	$ -	$ -	$ -	$ 2,015,055	$ 724,758	$ 2,015,055	$ 724,758	$ 22.40
16	CLALLAM PUD	$ 1.01	$ 4,228	$ (11,198)	$ (14.27)	$ 315.00	$ 113	$ -	$ -	$ -	$ -	$ 65,341	$ (134,375)	$ 65,341	$ (134,375)	$ (7.33)
17	MASON PUD3	$ 4.01	$ 7,196	$ 195	$ 0.32	$ -	$ 136	$ -	$ -	$ -	$ -	$ 116,803	$ 2,335	$ 116,803	$ 2,335	$ 16.57
18	PNGC	$ 0.26	$ 3,783	$ (1,880)	$ (0.85)	$ 2,550.00	$ -	$ -	$ -	$ -	$ -	$ 82,879	$ (22,561)	$ 82,879	$ (22,561)	$ 2.26
19	FLATHEAD	$ 0.15	$ 1,286	$ (851)	$ (1.47)	$ 637.00	$ -	$ -	$ -	$ -	$ -	$ 24,144	$ (10,217)	$ 24,144	$ (10,217)	$ 2.00
20	MISSION VALLEY	$ -	$ -	$ -	$ -	$ -	$ 1,080	$ -	$ -	$ -	$ -	$ 12,960	$ -	$ 12,960	$ -	$ 0.15
21	BENTON REA	$ -	$ -	$ -	$ -	$ -	$ 223	$ -	$ -	$ -	$ -	$ 2,677	$ -	$ 2,677	$ -	$ 0.23
22	BIG BEND	$ -	$ -	$ -	$ -	$ -	$ 179	$ -	$ -	$ -	$ -	$ 2,149	$ -	$ 2,149	$ -	$ 0.23
23	INLAND	$ -	$ -	$ -	$ -	$ -	$ 309	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,711	$ -	$ 0.23
24	IDAHO LIGHT & POWER	$ -	$ -	$ -	$ -	$ -	$ 46	$ -	$ -	$ -	$ -	$ 554	$ -	$ 554	$ -	$ 0.23
25	VERA ID	$ -	$ -	$ -	$ -	$ -	$ 177	$ -	$ -	$ -	$ -	$ 2,125	$ -	$ 2,125	$ -	$ 0.23
26	LOWER VALLEY	$ -	$ -	$ -	$ -	$ -	$ 139	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,665	$ -	$ 0.23
27	WELLS REC	$ -	$ -	$ -	$ -	$ -	$ 49	$ -	$ -	$ -	$ -	$ -	$ -	$ 593	$ -	$ 0.23
28	CHENEY	$ -	$ -	$ -	$ -	$ -	$ 49	$ -	$ -	$ -	$ -	$ 584	$ -	$ 584	$ -	$ 0.23
29	CENTRAL LINCOLN PUD	$ -	$ -	$ -	$ -	$ -	$ 162	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,939	$ -	$ 0.23
30	CENTRALIA	$ -	$ -	$ -	$ -	$ -	$ 82	$ -	$ -	$ -	$ -	$ 979	$ -	$ 979	$ -	$ 0.23
31	UNITED EC	$ -	$ -	$ -	$ -	$ -	$ 357	$ -	$ -	$ -	$ -	$ 4,288	$ -	$ 4,288	$ -	$ 0.23
32	COULUMBIA REA	$ -	$ -	$ -	$ -	$ -	$ 403	$ -	$ -	$ -	$ -	$ 4,835	$ -	$ 4,835	$ -	$ 0.23
33	RICHLAND	$ -	$ -	$ -	$ -	$ -	$ 284	$ -	$ -	$ -	$ -	$ 3,408	$ -	$ 3,408	$ -	$ 0.23
34	PENINSULA	$ -	$ -	$ -	$ -	$ -	$ 110	$ -	$ -	$ -	$ -	$ 1,323	$ -	$ 1,323	$ -	$ 0.23

Table 3.24
Irrigation Rate Discount (IRD) HLH/LLH Split

	A	B	C
1	**Irrigation Rate Discount (IRD) HLH/LLH Split**		
2	Average HLH/LLH split during irrigation months (4-yr averages):	59%	41%
3	Heavy irrigator HLH/LLH split during irrigation months (4-yr averages):	58%	42%
4	Light irrigator HLH/LLH split during irrigation months (4-yr averages):	60%	40%
5	MAX Split (4-yr averages):	62%	38%
6	MIN Split (4-yr averages):	52%	48%
7	MAX Split (1 month):	73%	27%
8	MIN Split (1 month):	42%	58%
9	* Percents *based on FY2006-2009 Metering Data*		

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SECTION 4: POWER REVENUE FORECASTS

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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
Subscription Contract Revenue – FY 2011
Table shows calculation of Subscription contract revenues at current rates.

Table 4.4
Subscription Contract Revenue – FY 2012-2013
Table shows calculation of Subscription contract revenues at current rates.

Table 4.5
Composite and Non-slice revenue – FY 2012-2013
Table shows calculation of CHWM revenues at proposed rates.

Table 4.6
Load Shaping and Demand revenue – FY 2012-2013
Table shows calculation of CHWM revenues at proposed rates.

Table 4.7
Irrigation Rate Discount (IRD) – FY 2012-2013
Table shows calculation of IRD credit at proposed rates.

Table 4.8
Low Density Discount (LDD) – FY 2012-2013
Table shows calculation of LDD credit at proposed rates.

Table 4.9
Tier 2 revenue – FY 2012-2013
Table shows calculation of CHWM revenues at proposed rates.

Table 4.10
Direct Service Industries (DSI) revenues – FY 2011-2013
Table shows calculation of DSI revenues at current and proposed rates.

Table 4.11
Forecasted Revenues from GTA Delivery Charge
Table shows the forecasted revenues from the GTA Delivery Charge for FY 2012 – 2013.

Addendum to Tables 4.1 and 4.2

Lines 3-9 (Subscription contracts) – See **Table 4.3** for FY 2011. See **Table 4.4** for FY 2012-2013.

Lines 10-12 (CHWM contracts – Composite, Non-Slice, and Slice) – See **Table 4.5**.

Lines 13-14 (Load Shaping and Demand) – See **Table 4.6**.

Line 15 (Irrigation Rate Discount) – See **Table 4.7**.

Line 16 (Low Density Discount) – See **Table 4.8**.

Line 17 (Tier 2) – See **Table 4.9**.

Line 18 (RSS) – Based on customer elections. See Power Rates Study, BP-12-FS-BPA-01, section 3.1.2.1.

Line 20 (Direct Service Industries) – See **Table 4.10**.

Line 22 (Short-Term Market Sales) – Short Term Market Sales numbers include a positive $3 million adjustment due to variable cost reduction for wind reserves relating to Direct Assignment Dec Acquisition Pilot Cost. See Power Market Price and Risk Study Documentation, BP-12-FS-BPA-04A, **Table 21**

Lines 37-49 (Inter- Business Unit / Gen Inputs for Ancillary and Other Services) – See Generation Inputs Study and Documentation, BP-12-FS-BPA-05(A)

Line 52 (4(h)(10)(C) credits) – See Power Market Price and Risk Study Documentation, BP-12-FS-BPA-04A, **Table 16**.

Line 55 (Augmentation) – See Power Market Price and Risk Study Documentation, BP-12-FS-BPA-04A, **Table 17**.

Line 58 (Balancing Power Purchase) - See Power Market Price and Risk Study Documentation, BP-12-FS-BPA-04A, **Table 22**.

Table 4.1 - Revenue at Current Rates

	B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1		**Table 4.1 - Revenue at Current Rates**													**2011**	
2		**Category**	**201010**	**201011**	**201012**	**201101**	**201102**	**201103**	**201104**	**201105**	**201106**	**201107**	**201108**	**201109**	**$ (000's)**	**aMW**
3	a)	PF Full Service (Load Following)	$ 42,718	$ 54,514	$ 62,788	$ 52,483	$ 49,464	$ 44,841	$ 38,579	$ 28,691	$ 23,454	$ 33,721	$ 39,315	$ 42,653	$ 513,221	2,054
4	a)	PF Partial Service (Load Following)	$ 31,540	$ 38,389	$ 43,050	$ 36,978	$ 35,415	$ 31,439	$ 27,255	$ 21,432	$ 18,025	$ 25,678	$ 30,757	$ 29,849	$ 369,808	1,442
5	b)	PF Block Service	$ 37,168	$ 46,793	$ 56,659	$ 48,281	$ 44,355	$ 42,527	$ 31,871	$ 21,396	$ 16,372	$ 24,161	$ 30,107	$ 38,025	$ 437,716	1,762
6		PF Slice	$ 44,005	$ 44,005	$ 44,005	$ 44,013	$ 44,007	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 528,134	2,183
7	c)	Irrigation Mitigation	$ 10	$ 10	$ 10	$ 10	$ 10	$ -	$ -	$ 3,700	$ 3,980	$ 7,382	$ 7,819	$ -	$ 22,929	198
8	d)	Low Density Discount (current rates only)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
9		**PF customers (Subscription) sub-total**	**$ 155,442**	**$ 183,711**	**$ 206,512**	**$ 181,765**	**$ 173,250**	**$ 162,821**	**$ 141,720**	**$ 119,233**	**$ 105,845**	**$ 134,956**	**$ 152,012**	**$ 154,541**	**$ 1,871,808**	**7,638**
20		**DSIs sub-total**	**$ 8,218**	**$ 8,516**	**$ 9,239**	**$ 9,682**	**$ 8,713**	**$ 9,077**	**$ 7,936**	**$ 7,406**	**$ 7,266**	**$ 8,432**	**$ 9,454**	**$ 9,139**	**$ 103,078**	**340**
21		**FPS sub-total**	**$ 3,167**	**$ 4,060**	**$ 4,584**	**$ 4,401**	**$ 4,145**	**$ 3,586**	**$ 2,851**	**$ 1,806**	**$ 1,771**	**$ 2,557**	**$ 3,108**	**$ 2,948**	**$ 38,985**	**168**
22		**Short-term market sales sub-total**	**$ 17,816**	**$ 17,085**	**$ 21,030**	**$ 49,674**	**$ 56,105**	**$ 68,844**	**$ 47,777**	**$ 45,544**	**$ 50,012**	**$ 51,774**	**$ 21,132**	**$ 16,376**	**$ 463,168**	**2,095**
23		**Long Term Contractual Obligations sub-total**	**$ 4,832**	**$ 11,389**	**$ 11,571**	**$ 11,581**	**$ 11,018**	**$ 8,442**	**$ 7,683**	**$ 8,445**	**$ 4,887**	**$ 4,883**	**$ 5,260**	**$ 39**	**$ 90,029**	**91**
24		**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**534**
25		**Renewable Energy Certificates sub-total**	**$ 537**	**$ 427**	**$ 307**	**$ 638**	**$ 278**	**$ 253**	**$ 245**	**$ 253**	**$ 245**	**$ 253**	**$ 253**	**$ 245**	**$ 3,934**	**-**
26		Network Wind Integration & Shaping	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 2,091	-
27		Miscellaneous Credits (incl. GTA)	$ 315	$ 401	$ 373	$ 368	$ 434	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,885	-
28		Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,942	$ 4,942	-
29		**Other Sales sub-total**	**$ 489**	**$ 575**	**$ 547**	**$ 542**	**$ 608**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 5,401**	**$ 10,918**	**-**
30		**Gross Sales**	**$ 190,501**	**$ 225,762**	**$ 253,789**	**$ 258,284**	**$ 254,116**	**$ 253,484**	**$ 208,671**	**$ 183,147**	**$ 170,485**	**$ 203,315**	**$ 191,678**	**$ 188,689**	**$ 2,581,920**	**10,867**
31		Energy Efficiency Revenues	$ 1,751	$ 637	$ 899	$ 1,081	$ 90	$ 390	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 11,500	-
32		Irrigation Pumping Power	$ 30	$ 0	$ 1	$ 1	$ 1	$ 7	$ 42	$ 95	$ 129	$ 164	$ 148	$ 218	$ 836	174
33		Reserve Energy	$ 721	$ 721	$ 721	$ 721	$ 721	$ 565	$ 731	$ 731	$ 731	$ 731	$ 731	$ 731	$ 8,554	3
34		Downstream Benefits	$ 383	$ 393	$ 445	$ 415	$ 376	$ 376	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,607	-
35		Upper Baker Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	3
36		**Miscellaneous Revenues**	**$ 2,885**	**$ 1,752**	**$ 2,065**	**$ 2,217**	**$ 1,188**	**$ 1,414**	**$ 2,251**	**$ 2,304**	**$ 2,339**	**$ 2,373**	**$ 2,357**	**$ 2,427**	**$ 25,572**	**180**
37		Regulating Reserve	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 7,699	-
38		Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$ 3,608	$ 3,614	$ 3,659	$ 3,751	$ 3,755	$ 3,700	$ 3,805	$ 3,804	$ 3,809	$ 4,005	$ 4,143	$ 4,289	$ 45,944	-
39		Committed Intra-Hour Scheduling Pilot Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40		VERBS Reserve Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41		Dispatchable Energy Reseource Balancing Service Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42		Operating Reserve - Spinning	$ 1,325	$ 1,381	$ 1,394	$ 1,506	$ 1,439	$ 1,419	$ 1,419	$ 1,448	$ 1,433	$ 1,501	$ 1,446	$ 1,321	$ 17,032	-
43		Operating Reserve - Supplemental	$ 1,280	$ 1,334	$ 1,347	$ 1,456	$ 1,390	$ 1,371	$ 1,371	$ 1,399	$ 1,384	$ 1,451	$ 1,398	$ 1,276	$ 16,458	-
44		Synchronous Condensing	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 1,954	-
45		Generation Dropping	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 612	-
46		Generation Imbalance/Energy Imbalance/Persistent Deviation	$ 548	$ 702	$ 658	$ 477	$ 437	$ 435	$ 176	$ 153	$ 188	$ 340	$ 339	$ 382	$ 4,834	-
47		Contingency Energy	$ 113	$ 171	$ 70	$ 57	$ 50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 461	-
48		Redispatch	$ 11	$ 415	$ -	$ 4	$ 0	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 664	-
49		COE/Reclamation Network/Delivery Facilities Segmentation	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 6,362	-
50		Station Service	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 3,229	9
51		**Generation Inputs / Inter-business line**	**$ 8,540**	**$ 9,271**	**$ 8,782**	**$ 8,907**	**$ 8,726**	**$ 8,614**	**$ 8,459**	**$ 8,492**	**$ 8,502**	**$ 8,985**	**$ 9,014**	**$ 8,956**	**$ 105,249**	**9**
52		4(h)(10)(c)	$ 10,539	$ 11,613	$ 3,614	$ 8,600	$ 10,880	$ 5,650	$ 5,896	$ 5,896	$ 5,896	$ 5,861	$ 5,985	$ 6,581	$ 87,013	-
53		Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54		**Treasury Credits**	**$ 10,922**	**$ 11,996**	**$ 3,998**	**$ 8,983**	**$ 11,264**	**$ 6,033**	**$ 6,280**	**$ 6,280**	**$ 6,280**	**$ 6,244**	**$ 6,368**	**$ 6,965**	**$ 91,613**	**-**
55		Augmentation Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56		ERE augmentation purchases	$ 258	$ 292	$ 298	$ 254	$ 238	$ 227	$ 172	$ 197	$ 158	$ 236	$ 260	$ 253	$ 2,843	11
57		**Augmentation Power Purchase total**	**$ 258**	**$ 292**	**$ 298**	**$ 254**	**$ 238**	**$ 227**	**$ 172**	**$ 197**	**$ 158**	**$ 236**	**$ 260**	**$ 253**	**$ 2,843**	**11**
58		**Balancing Power Purchase sub-total**	**$ 25,129**	**$ 25,221**	**$ 34,193**	**$ 19,592**	**$ 7,967**	**$ 2,380**	**$ 10,253**	**$ 4,110**	**$ 157**	**$ 3,802**	**$ 12,677**	**$ 11,748**	**$ 157,229**	**480**
59		**Other Power Purchase total**	**$ 45**	**$ 8,079**	**$ 8,118**	**$ 7,919**	**$ 7,542**	**$ 7,801**	**$ 7,518**	**$ 149**	**$ 149**	**$ 149**	**$ 149**	**$ 149**	**$ 47,767**	**93**
60		**Power Purchases**	**$ 25,431**	**$ 33,592**	**$ 42,609**	**$ 27,765**	**$ 15,747**	**$ 10,408**	**$ 17,943**	**$ 4,456**	**$ 464**	**$ 4,187**	**$ 13,086**	**$ 12,150**	**$ 207,839**	**583**
61		a) all Full Service and Partial Service contracts are considered Load Following in FY 12-13 and are listed on line 3.														
62		b) represents the Slice/Block product in FY12-13														
63		c) In FY 11, Irrigation Mitigation product is represented as a sale under the FPS rate schedule. In FY 12-13, Irrigation Rate Discount product is represented as a credit to PF customers.														
64		d) In FY 11, LDD consolidated into Load Following, Block, and Slice products. In FY 12-13, LDD is separated into its own category.														

Table 4.1 - Revenue at Current Rates

	B C D	E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1		**Table 4.1 - Revenue at Current Rates**													**2012**	
2		**Category**	**201110**	**201111**	**201112**	**201201**	**201202**	**201203**	**201204**	**201205**	**201206**	**201207**	**201208**	**201209**	**$ (000's)**	**aMW**
3	a)	PF Full Service (Load Following)	$ 68,356	$ 80,116	$ 100,055	$ 82,728	$ 74,356	$ 67,090	$ 58,014	$ 47,792	$ 41,374	$ 60,177	$ 69,012	$ 64,915	$ 813,985	3,190
4	a)	PF Partial Service (Load Following)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
5	b)	PF Block Service	$ 37,300	$ 47,645	$ 57,470	$ 48,999	$ 42,128	$ 40,373	$ 30,348	$ 22,400	$ 17,124	$ 27,794	$ 33,124	$ 35,304	$ 440,008	1,791
6		PF Slice	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 636,495	1,879
7	c)	Irrigation Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,030)	$ (3,034)	$ (3,495)	$ (2,868)	$ (1,745)	$ (13,172)	-
8	d)	Low Density Discount (current rates only)	$ (2,221)	$ (2,548)	$ (3,289)	$ (2,655)	$ (2,368)	$ (2,147)	$ (1,892)	$ (1,484)	$ (1,492)	$ (2,218)	$ (2,482)	$ (2,243)	$ (27,039)	-
9		**PF customers (Subscription) sub-total**	**$ 156,475**	**$ 178,254**	**$ 207,278**	**$ 182,113**	**$ 167,157**	**$ 158,356**	**$ 139,512**	**$ 119,719**	**$ 107,013**	**$ 135,299**	**$ 149,827**	**$ 149,273**	**$ 1,850,277**	**6,860**
20		**DSIs sub-total**	**$ 8,223**	**$ 8,506**	**$ 9,238**	**$ 9,666**	**$ 9,000**	**$ 9,087**	**$ 7,906**	**$ 7,458**	**$ 7,266**	**$ 8,432**	**$ 9,453**	**$ 9,116**	**$ 103,350**	**341**
21		**FPS sub-total**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 1,716**	**8**
22		**Short-term market sales sub-total**	**$ 11,748**	**$ 13,257**	**$ 16,187**	**$ 34,548**	**$ 32,692**	**$ 36,740**	**$ 57,280**	**$ 79,478**	**$ 73,864**	**$ 53,463**	**$ 24,329**	**$ 13,742**	**$ 447,327**	**1,769**
23		**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,405**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 30,217**	**65**
24		**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**522**
25		**Renewable Energy Certificates sub-total**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 2,658**	**40**
26		Network Wind Integration & Shaping	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 2,086	-
27		Miscellaneous Credits (incl. GTA)	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,420	-
28		Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
29		**Other Sales sub-total**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 5,506**	**-**
30		**Gross Sales**	**$ 177,309**	**$ 206,734**	**$ 239,931**	**$ 233,193**	**$ 215,204**	**$ 208,033**	**$ 208,452**	**$ 207,557**	**$ 189,053**	**$ 198,100**	**$ 184,493**	**$ 172,993**	**$ 2,441,051**	**9,605**
31		Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
32		Irrigation Pumping Power	$ 72	$ 1	$ 1	$ 1	$ 1	$ 9	$ 76	$ 165	$ 200	$ 255	$ 237	$ 166	$ 1,184	174
33		Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
34		Downstream Benefits	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,435	-
35		Upper Baker Revenues	$ -	$ 89	$ 94	$ 88	$ 89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 360	1
36		**Miscellaneous Revenues**	**$ 2,126**	**$ 2,144**	**$ 2,149**	**$ 2,144**	**$ 2,145**	**$ 2,063**	**$ 2,131**	**$ 2,220**	**$ 2,255**	**$ 2,310**	**$ 2,291**	**$ 2,220**	**$ 26,198**	**178**
37		Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
38		Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$ 3,649	$ 3,649	$ 3,649	$ 3,649	$ 3,649	$ 3,957	$ 4,314	$ 4,314	$ 4,314	$ 4,314	$ 4,733	$ 4,845	$ 49,036	-
39		Committed Intra-Hour Scheduling Pilot Adjustment	$ -	$ -	$ -	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (2,258)	-
40		VERBS Reserve Solar	$ -	$ -	$ -	$ 1	$ 1	$ 1	$ 3	$ 3	$ 7	$ 7	$ 7	$ 7	$ 35	-
41		Dispatchable Energy Reseource Balancing Service Reserve	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 5,753	-
42		Operating Reserve - Spinning	$ 2,320	$ 2,317	$ 2,639	$ 2,608	$ 2,319	$ 2,509	$ 2,448	$ 2,523	$ 2,618	$ 2,714	$ 2,632	$ 2,338	$ 29,987	-
43		Operating Reserve - Supplemental	$ 1,972	$ 1,969	$ 2,243	$ 2,216	$ 1,971	$ 2,133	$ 2,081	$ 2,144	$ 2,225	$ 2,307	$ 2,237	$ 1,987	$ 25,483	-
44		Synchronous Condensing	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 1,902	-
45		Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
46		Generation Imbalance/Energy Imbalance/Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47		Contingency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48		Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
49		COE/Reclamation Network/Delivery Facilities Segmentation	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 7,183	-
50		Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
51		**Generation Inputs / Inter-business line**	**$ 10,039**	**$ 10,032**	**$ 10,628**	**$ 10,320**	**$ 9,787**	**$ 10,446**	**$ 10,692**	**$ 10,831**	**$ 11,010**	**$ 11,187**	**$ 11,455**	**$ 11,022**	**$ 127,449**	**9**
52		4(h)(10)(c)	$ 9,995	$ 8,314	$ 10,076	$ 9,932	$ 8,919	$ 8,142	$ 6,323	$ 5,541	$ 5,764	$ 5,157	$ 5,965	$ 6,934	$ 91,062	-
53		Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54		**Treasury Credits**	**$ 10,378**	**$ 8,698**	**$ 10,459**	**$ 10,315**	**$ 9,302**	**$ 8,526**	**$ 6,707**	**$ 5,924**	**$ 6,147**	**$ 5,541**	**$ 6,348**	**$ 7,317**	**$ 95,662**	**-**
55		Augmentation Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56		ERE augmentation purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57		**Augmentation Power Purchase total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
58		**Balancing Power Purchase sub-total**	**$ 9,840**	**$ 6,751**	**$ 10,228**	**$ 2,441**	**$ 2,576**	**$ 2,173**	**$ 392**	**$ -**	**$ -**	**$ 1,604**	**$ 3,822**	**$ 7,000**	**$ 46,827**	**231**
59		**Other Power Purchase total**	**$ 704**	**$ 7,866**	**$ 8,436**	**$ 8,153**	**$ 7,869**	**$ 8,356**	**$ 8,072**	**$ 704**	**$ 704**	**$ 704**	**$ 704**	**$ 704**	**$ 52,974**	**105**
60		**Power Purchases**	**$ 10,544**	**$ 14,617**	**$ 18,664**	**$ 10,594**	**$ 10,446**	**$ 10,528**	**$ 8,464**	**$ 704**	**$ 704**	**$ 2,308**	**$ 4,525**	**$ 7,704**	**$ 99,802**	**335**

61 a) all Full Service and Partial Service contracts are considered Load Following in FY 12-13 and are listed on line 3.

62 b) represents the Slice/Block product in FY12-13

63 c) In FY 11, Irrigation Mitigation product is represented as a sale under the FPS rate schedule. In FY 12-13, Irrigation Rate Discount product is represented as a credit to PF customers.

64 d) In FY 11, LDD consolidated into Load Following, Block, and Slice products. In FY 12-13, LDD is separated into its own category.

Table 4.1 - Revenue at Current Rates

	B C D	E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.1 - Revenue at Current Rates**														2013	
2	**Category**		201210	201211	201212	201301	201302	201303	201304	201305	201306	201307	201308	201309	$ (000's)	aMW
3	a)	PF Full Service (Load Following)	$ 69,535	$ 81,729	$ 101,796	$ 84,160	$ 74,906	$ 68,452	$ 59,136	$ 48,943	$ 42,262	$ 61,601	$ 70,477	$ 66,299	$ 829,296	3,240
4	a)	PF Partial Service (Load Following)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
5	b)	PF Block Service	$ 38,215	$ 48,572	$ 57,916	$ 49,983	$ 43,078	$ 40,916	$ 31,118	$ 22,855	$ 17,284	$ 28,508	$ 33,764	$ 35,960	$ 448,171	1,831
6		PF Slice	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 53,041	$ 636,495	1,879
7	c)	Irrigation Mitigation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,030)	$ (3,034)	$ (3,495)	$ (2,868)	$ (1,745)	$ (13,172)	-
8	d)	Low Density Discount (current rates only)	$ (2,323)	$ (2,671)	$ (3,434)	$ (2,775)	$ (2,469)	$ (2,250)	$ (1,984)	$ (1,763)	$ (1,565)	$ (2,334)	$ (2,606)	$ (2,356)	$ (28,531)	-
9		**PF customers (Subscription) sub-total**	**$ 158,468**	**$ 180,672**	**$ 209,320**	**$ 184,409**	**$ 168,556**	**$ 160,160**	**$ 141,311**	**$ 121,046**	**$ 107,988**	**$ 137,322**	**$ 151,808**	**$ 151,200**	**$ 1,872,259**	**6,951**
20		**DSIs sub-total**	**$ 8,249**	**$ 8,506**	**$ 9,216**	**$ 9,700**	**$ 8,708**	**$ 9,056**	**$ 7,934**	**$ 7,458**	**$ 7,223**	**$ 8,458**	**$ 9,453**	**$ 9,116**	**$ 103,076**	**341**
21		**FPS sub-total**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 1,778**	**8**
22		**Short-term market sales sub-total**	**$ 11,749**	**$ 14,911**	**$ 20,431**	**$ 41,434**	**$ 33,885**	**$ 42,391**	**$ 66,881**	**$ 76,527**	**$ 61,193**	**$ 50,024**	**$ 26,561**	**$ 13,665**	**$ 459,653**	**1,652**
23		**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**	**62**
24		**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**505**
25		**Renewable Energy Certificates sub-total**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 2,836**	**40**
26		Network Wind Integration & Shaping	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 2,078	-
27		Miscellaneous Credits (incl. GTA)	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,420	-
28		Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
29		**Other Sales sub-total**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 5,498**	**-**
30	**Gross Sales**		**$ 179,349**	**$ 210,824**	**$ 245,861**	**$ 242,427**	**$ 217,524**	**$ 215,476**	**$ 219,900**	**$ 205,953**	**$ 177,332**	**$ 196,728**	**$ 188,727**	**$ 174,861**	**$ 2,474,965**	**9,560**
31		Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
32		Irrigation Pumping Power	$ 79	$ 1	$ 1	$ 1	$ 1	$ 9	$ 84	$ 181	$ 216	$ 275	$ 256	$ 181	$ 1,284	174
33		Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
34		Downstream Benefits	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,435	-
35		Upper Baker Revenues	$ -	$ 96	$ 101	$ 99	$ 101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397	1
36	**Miscellaneous Revenues**		**$ 2,134**	**$ 2,151**	**$ 2,157**	**$ 2,154**	**$ 2,157**	**$ 2,063**	**$ 2,138**	**$ 2,236**	**$ 2,270**	**$ 2,330**	**$ 2,311**	**$ 2,235**	**$ 26,335**	**178**
37		Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
38		Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$ 4,845	$ 4,845	$ 5,252	$ 5,252	$ 5,345	$ 5,345	$ 5,345	$ 5,345	$ 5,345	$ 5,406	$ 5,547	$ 5,547	$ 63,417	-
39		Committed Intra-Hour Scheduling Pilot Adjustment	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (3,011)	-
40		VERBS Reserve Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 78	-
41		Dispatchable Energy Reseource Balancing Service Reserve	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 5,753	-
42		Operating Reserve - Spinning	$ 1,901	$ 1,898	$ 2,162	$ 2,136	$ 1,900	$ 2,056	$ 2,006	$ 2,068	$ 2,145	$ 2,224	$ 2,157	$ 1,915	$ 24,570	-
43		Operating Reserve - Supplemental	$ 1,616	$ 1,613	$ 1,837	$ 1,816	$ 1,615	$ 1,747	$ 1,705	$ 1,757	$ 1,823	$ 1,890	$ 1,833	$ 1,628	$ 20,880	-
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		Generation Imbalance/Energy Imbalance/Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47		Contingency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48		Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
49		COE/Reclamation Network/Delivery Facilities Segmentation	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 7,183	-
50		Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
51	**Generation Inputs / Inter-business line**		**$ 10,213**	**$ 10,208**	**$ 11,103**	**$ 11,055**	**$ 10,711**	**$ 10,999**	**$ 10,906**	**$ 11,020**	**$ 11,164**	**$ 11,371**	**$ 11,388**	**$ 10,941**	**$ 131,078**	**9**
52		4(h)(10)(c)	$ 10,966	$ 8,749	$ 10,658	$ 10,767	$ 9,446	$ 8,717	$ 6,566	$ 5,625	$ 5,865	$ 5,187	$ 6,112	$ 7,189	$ 95,847	-
53		Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**		**$ 11,350**	**$ 9,132**	**$ 11,041**	**$ 11,150**	**$ 9,830**	**$ 9,100**	**$ 6,950**	**$ 6,008**	**$ 6,248**	**$ 5,571**	**$ 6,495**	**$ 7,572**	**$ 100,447**	**-**
55		Augmentation Purchases	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 66,150	176
56		ERE augmentation purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57		**Augmentation Power Purchase total**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 66,150**	**176**
58		**Balancing Power Purchase sub-total**	**$ 5,614**	**$ 4,637**	**$ 8,029**	**$ 800**	**$ 1,501**	**$ 998**	**$ 4**	**$ -**	**$ -**	**$ 1,322**	**$ 2,215**	**$ 4,441**	**$ 29,559**	**140**
59		**Other Power Purchase total**	**$ 1,952**	**$ 8,750**	**$ 9,320**	**$ 9,037**	**$ 8,753**	**$ 9,603**	**$ 9,320**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 66,492**	**140**
60	**Power Purchases**		**$ 13,078**	**$ 18,899**	**$ 22,861**	**$ 15,350**	**$ 15,766**	**$ 16,114**	**$ 14,836**	**$ 7,464**	**$ 7,464**	**$ 8,786**	**$ 9,679**	**$ 11,905**	**$ 162,201**	**456**
61	a) all Full Service and Partial Service contracts are considered Load Following in FY 12-13 and are listed on line 3.															
62	b) represents the Slice/Block product in FY12-13															
63	c) In FY 11, Irrigation Mitigation product is represented as a sale under the FPS rate schedule. In FY 12-13, Irrigation Rate Discount product is represented as a credit to PF customers.															
64	d) In FY 11, LDD consolidated into Load Following, Block, and Slice products. In FY 12-13, LDD is separated into its own category.															

Table 4.2 - Revenue at Proposed Rates

	B C D E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**Table 4.2 - Revenue at Proposed Rates**													**2011**	
2	**Category**	**201010**	**201011**	**201012**	**201101**	**201102**	**201103**	**201104**	**201105**	**201106**	**201107**	**201108**	**201109**	**$ (000's)**	**aMW**
3	PF Full Service	$42,718	$54,514	$ 62,788	$ 52,483	$ 49,464	$ 44,841	$ 38,579	$ 28,691	$ 23,454	$ 33,721	$ 39,315	$ 42,653	$ 513,221	2,054
4	PF Partial Service	$31,540	$38,389	$ 43,050	$ 36,978	$ 35,415	$ 31,439	$ 27,255	$ 21,432	$ 18,025	$ 25,678	$ 30,757	$ 29,849	$ 369,808	1,442
5	PF Block Service	$37,168	$46,793	$ 56,659	$ 48,281	$ 44,355	$ 42,527	$ 31,871	$ 21,396	$ 16,372	$ 24,161	$ 30,107	$ 38,025	$ 437,716	1,762
6	PF Slice	$44,005	$44,005	$ 44,005	$ 44,013	$ 44,007	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 44,014	$ 528,134	2,183
7	Irrigation Mitigation	$10	$10	$ 10	$ 10	$ 10	$ -	$ -	$ 3,700	$ 3,980	$ 7,382	$ 7,819	$ -	$ 22,929	198
8	Low Density Discount (current rates only)	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
9	**PF customers (Subscription) sub-total**	**$155,442**	**$183,711**	**$ 206,512**	**$ 181,765**	**$ 173,250**	**$ 162,821**	**$ 141,720**	**$ 119,233**	**$ 105,845**	**$ 134,956**	**$ 152,012**	**$ 154,541**	**$ 1,871,808**	**7,638**
10	Composite Revenue														
11	Non-Slice Revenue														
12	Slice														
13	Load Shaping Revenue														
14	Demand Revenue														
15	Irrig. Mit.														
16	Low Density Discount														
17	Tier 2														
18	RSS (Non-Federal)														
19	**PF customers (CHWM) sub-total**	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
20	**DSIs sub-total**	**$8,218**	**$8,516**	**$ 9,239**	**$ 9,682**	**$ 8,713**	**$ 9,077**	**$ 7,936**	**$ 7,406**	**$ 7,266**	**$ 8,432**	**$ 9,454**	**$ 9,139**	**$ 103,078**	**340**
21	**FPS sub-total**	**$3,167**	**$4,060**	**$ 4,584**	**$ 4,401**	**$ 4,145**	**$ 3,586**	**$ 2,851**	**$ 1,806**	**$ 1,771**	**$ 2,557**	**$ 3,108**	**$ 2,948**	**$ 38,985**	**168**
22	**Short-term market sales sub-total**	**$17,816**	**$17,085**	**$ 21,030**	**$ 49,674**	**$ 56,105**	**$ 68,844**	**$ 47,777**	**$ 45,544**	**$ 50,012**	**$ 51,774**	**$ 21,132**	**$ 16,376**	**$ 463,168**	**2,095**
23	**Long Term Contractual Obligations sub-total**	**$4,832**	**$11,389**	**$ 11,571**	**$ 11,581**	**$ 11,018**	**$ 8,442**	**$ 7,683**	**$ 8,445**	**$ 4,887**	**$ 4,883**	**$ 5,260**	**$ 39**	**$ 90,029**	**91**
24	**Canadian Entitlement Return**	**$0**	**$0**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**534**
25	**Renewable Energy Certificates sub-total**	**$537**	**$427**	**$ 307**	**$ 638**	**$ 278**	**$ 253**	**$ 245**	**$ 253**	**$ 245**	**$ 253**	**$ 253**	**$ 245**	**$ 3,934**	**-**
26	Network Wind Integration & Shaping	$174	$174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 2,091	-
27	Miscellaneous Credits (incl. GTA)	$315	$401	$ 373	$ 368	$ 434	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,885	-
28	Slice True up	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,942	$ 4,942	-
29	**Other Sales sub-total**	**$489**	**$575**	**$ 547**	**$ 542**	**$ 608**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 5,401**	**$ 10,918**	**-**
30	**Gross Sales**	**$190,501**	**$225,762**	**$ 253,789**	**$ 258,284**	**$ 254,116**	**$ 253,484**	**$ 208,671**	**$ 183,147**	**$ 170,485**	**$ 203,315**	**$ 191,678**	**$ 188,689**	**$ 2,581,920**	**10,867**
31	Energy Efficiency Revenues	$1,751	$637	$ 899	$ 1,081	$ 90	$ 390	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 1,109	$ 11,500	-
32	Irrigation Pumping Power	$30	$0	$ 1	$ 1	$ 1	$ 7	$ 42	$ 95	$ 129	$ 164	$ 148	$ 218	$ 836	174
33	Reserve Energy	$721	$721	$ 721	$ 721	$ 721	$ 565	$ 731	$ 731	$ 731	$ 731	$ 731	$ 731	$ 8,554	3
34	Downstream Benefits	$383	$393	$ 445	$ 415	$ 376	$ 376	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,607	-
35	US Bureau of Reclamation	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	3
36	**Miscellaneous Revenues**	**$2,885**	**$1,752**	**$ 2,065**	**$ 2,217**	**$ 1,188**	**$ 1,414**	**$ 2,251**	**$ 2,304**	**$ 2,339**	**$ 2,373**	**$ 2,357**	**$ 2,427**	**$ 25,572**	**180**
37	Regulating Reserve	$642	$642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 642	$ 7,699	-
38	Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$3,608	$3,614	$ 3,659	$ 3,751	$ 3,755	$ 3,700	$ 3,805	$ 3,804	$ 3,809	$ 4,005	$ 4,143	$ 4,289	$ 45,944	-
39	Committed Intra-Hour Scheduling Pilot Adjustment	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	VERBS Reserve Solar	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Dispatchable Energy Reseource Balancing Service Reserve	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Operating Reserve - Spinning	$1,325	$1,381	$ 1,394	$ 1,506	$ 1,439	$ 1,419	$ 1,419	$ 1,448	$ 1,433	$ 1,501	$ 1,446	$ 1,321	$ 17,032	-
43	Operating Reserve - Supplemental	$1,280	$1,334	$ 1,347	$ 1,456	$ 1,390	$ 1,371	$ 1,371	$ 1,399	$ 1,384	$ 1,451	$ 1,398	$ 1,276	$ 16,458	-
44	Synchronous Condensing	$163	$163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 1,954	-
45	Generation Dropping	$51	$51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 612	-
46	Generation Imbalance/Energy Imbalance/Persistent Deviation	$548	$702	$ 658	$ 477	$ 437	$ 435	$ 176	$ 153	$ 188	$ 340	$ 339	$ 382	$ 4,834	-
47	Contingency Energy	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Redispatch	$11	$415	$ -	$ 4	$ 0	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 664	-
49	COE/Reclamation Network/Delivery Facilities Segmentation	$530	$530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 530	$ 6,362	-
50	Station Service	$269	$269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 269	$ 3,229	9
51	**Generation Inputs / Inter-business line**	**$8,540**	**$9,271**	**$ 8,782**	**$ 8,907**	**$ 8,726**	**$ 8,614**	**$ 8,459**	**$ 8,492**	**$ 8,502**	**$ 8,985**	**$ 9,014**	**$ 8,956**	**$ 105,249**	**9**
52	4(h)(10)(c)	$10,539	$11,613	$ 3,614	$ 8,600	$ 10,880	$ 5,650	$ 5,896	$ 5,896	$ 5,896	$ 5,861	$ 5,985	$ 6,581	$ 87,013	-
53	Colville and Spokane Settlements	$383	$383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$10,922**	**$11,996**	**$ 3,998**	**$ 8,983**	**$ 11,264**	**$ 6,033**	**$ 6,280**	**$ 6,280**	**$ 6,280**	**$ 6,244**	**$ 6,368**	**$ 6,965**	**$ 91,613**	**-**
55	Augmentation Purchases	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	ERE augmentation purchases	$258	$292	$ 298	$ 254	$ 238	$ 227	$ 172	$ 197	$ 158	$ 236	$ 260	$ 253	$ 2,843	11
57	**Augmentation Power Purchase sub-total**	**$258**	**$292**	**$ 298**	**$ 254**	**$ 238**	**$ 227**	**$ 172**	**$ 197**	**$ 158**	**$ 236**	**$ 260**	**$ 253**	**$ 2,843**	**11**
58	**Balancing Power Purchase sub-total**	**$25,129**	**$25,221**	**$ 34,193**	**$ 19,592**	**$ 7,967**	**$ 2,380**	**$ 10,253**	**$ 4,110**	**$ 157**	**$ 3,802**	**$ 12,677**	**$ 11,748**	**$ 157,229**	**480**
59	**Other Power Purchase sub-total**	**$45**	**$8,079**	**$ 8,118**	**$ 7,919**	**$ 7,542**	**$ 7,801**	**$ 7,518**	**$ 149**	**$ 149**	**$ 149**	**$ 149**	**$ 149**	**$ 47,767**	**93**
60	**Power Purchases**	**$25,431**	**$33,592**	**$ 42,609**	**$ 27,765**	**$ 15,747**	**$ 10,408**	**$ 17,943**	**$ 4,456**	**$ 464**	**$ 4,187**	**$ 13,086**	**$ 12,150**	**$ 207,839**	**583**

Table 4.2 - Revenue at Proposed Rates

	B C D E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Table 4.2 - Revenue at Proposed Rates**													**2012**	
2	**Category**	**201110**	**201111**	**201112**	**201201**	**201202**	**201203**	**201204**	**201205**	**201206**	**201207**	**201208**	**201209**	**$ (000's)**	**aMW**
3	PF Full Service														
4	PF Partial Service														
5	PF Block Service														
6	PF Slice														
7	Irrigation Mitigation														
8	Low Density Discount (current rates only)														
9	**PF customers (Subscription) sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
10	Composite Revenue	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 187,403	$ 2,248,831	6,911
11	Non-Slice Revenue	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (26,879)	$ (322,551)	-
12	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	Load Shaping Revenue	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 717	$ 8,604	21
14	Demand Revenue	$ 1,898	$ (6,378)	$ 18,922	$ 16,192	$ 18,301	$ 16,117	$ 24,658	$ (44,227)	$ (25,124)	$ (25,882)	$ (2,806)	$ (8,579)	$ (16,910)	(33)
15	Irrig. Mit.	$ 3,714	$ 3,627	$ 8,974	$ 5,772	$ 5,160	$ 5,844	$ 3,978	$ 3,772	$ 4,406	$ 4,179	$ 5,920	$ 3,586	$ 58,932	-
16	Low Density Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,976)	$ (4,447)	$ (5,122)	$ (4,203)	$ (2,557)	$ (19,305)	-
17	Tier 2	$ (2,549)	$ (2,218)	$ (3,053)	$ (2,804)	$ (2,856)	$ (2,788)	$ (3,117)	$ (1,835)	$ (2,454)	$ (2,532)	$ (3,022)	$ (2,541)	$ (31,768)	-
18	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 309	-
19	**PF customers (CHWM) sub-total**	**$ 164,329**	**$ 156,298**	**$ 186,109**	**$ 180,426**	**$ 181,870**	**$ 180,439**	**$ 186,785**	**$ 116,000**	**$ 133,646**	**$ 131,910**	**$ 157,155**	**$ 151,175**	**$ 1,926,143**	**6,900**
20	**DSIs sub-total**	**$ 9,012**	**$ 8,818**	**$ 9,716**	**$ 9,330**	**$ 9,072**	**$ 9,409**	**$ 8,584**	**$ 7,856**	**$ 7,637**	**$ 9,398**	**$ 10,104**	**$ 9,683**	**$ 108,618**	**341**
21	**FPS sub-total**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 143**	**$ 1,716**	**8**
22	**Short-term market sales sub-total**	**$ 11,748**	**$ 13,257**	**$ 16,187**	**$ 34,548**	**$ 32,692**	**$ 36,740**	**$ 57,280**	**$ 79,478**	**$ 73,864**	**$ 53,463**	**$ 24,329**	**$ 13,742**	**$ 447,327**	**1,769**
23	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,405**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 30,217**	**65**
24	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**522**
25	**Renewable Energy Certificates sub-total**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 222**	**$ 2,658**	**40**
26	Network Wind Integration & Shaping	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 174	$ 2,086	-
27	Miscellaneous Credits (incl. GTA)	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,420	-
28	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
29	**Other Sales sub-total**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 459**	**$ 5,506**	**-**
30	**Gross Sales**	**$ 185,953**	**$ 185,089**	**$ 219,240**	**$ 231,169**	**$ 229,989**	**$ 230,437**	**$ 256,403**	**$ 204,237**	**$ 216,057**	**$ 195,677**	**$ 192,473**	**$ 175,463**	**$ 2,522,186**	**9,645**
31	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
32	Irrigation Pumping Power	$ 72	$ 1	$ 1	$ 1	$ 1	$ 9	$ 76	$ 165	$ 200	$ 255	$ 237	$ 166	$ 1,184	174
33	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
34	Downstream Benefits	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,435	-
35	US Bureau of Reclamation	$ -	$ 89	$ 94	$ 88	$ 89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 360	1
36	**Miscellaneous Revenues**	**$ 2,126**	**$ 2,144**	**$ 2,149**	**$ 2,144**	**$ 2,145**	**$ 2,063**	**$ 2,131**	**$ 2,220**	**$ 2,255**	**$ 2,310**	**$ 2,291**	**$ 2,220**	**$ 26,198**	**178**
37	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
38	Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$ 3,649	$ 3,649	$ 3,649	$ 3,649	$ 3,649	$ 3,957	$ 4,314	$ 4,314	$ 4,314	$ 4,314	$ 4,733	$ 4,845	$ 49,036	-
39	Committed Intra-Hour Scheduling Pilot Adjustment	$ -	$ -	$ -	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (2,258)	-
40	VERBS Reserve Solar	$ -	$ -	$ -	$ 1	$ 1	$ 1	$ 3	$ 3	$ 7	$ 7	$ 7	$ 7	$ 35	-
41	Dispatchable Energy Reseource Balancing Service Reserve	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 5,753	-
42	Operating Reserve - Spinning	$ 2,320	$ 2,317	$ 2,639	$ 2,608	$ 2,319	$ 2,509	$ 2,448	$ 2,523	$ 2,618	$ 2,714	$ 2,632	$ 2,338	$ 29,987	-
43	Operating Reserve - Supplemental	$ 1,972	$ 1,969	$ 2,243	$ 2,216	$ 1,971	$ 2,133	$ 2,081	$ 2,144	$ 2,225	$ 2,307	$ 2,237	$ 1,987	$ 25,483	-
44	Synchronous Condensing	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 158	$ 1,902	-
45	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
46	Generation Imbalance/Energy Imbalance/Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Contingency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
49	COE/Reclamation Network/Delivery Facilities Segmentation	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 7,183	-
50	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
51	**Generation Inputs / Inter-business line**	**$ 10,039**	**$ 10,032**	**$ 10,628**	**$ 10,320**	**$ 9,787**	**$ 10,446**	**$ 10,692**	**$ 10,831**	**$ 11,010**	**$ 11,187**	**$ 11,455**	**$ 11,022**	**$ 127,449**	**9**
52	4(h)(10)(c)	$ 9,995	$ 8,314	$ 10,076	$ 9,932	$ 8,919	$ 8,142	$ 6,323	$ 5,541	$ 5,764	$ 5,157	$ 5,965	$ 6,934	$ 91,062	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 10,378**	**$ 8,698**	**$ 10,459**	**$ 10,315**	**$ 9,302**	**$ 8,526**	**$ 6,707**	**$ 5,924**	**$ 6,147**	**$ 5,541**	**$ 6,348**	**$ 7,317**	**$ 95,662**	**-**
55	Augmentation Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	ERE augmentation purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57	**Augmentation Power Purchase sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
58	**Balancing Power Purchase sub-total**	**$ 9,840**	**$ 6,751**	**$ 10,228**	**$ 2,441**	**$ 2,576**	**$ 2,173**	**$ 392**	**$ -**	**$ -**	**$ 1,604**	**$ 3,822**	**$ 7,000**	**$ 46,827**	**231**
59	**Other Power Purchase sub-total**	**$ 704**	**$ 7,866**	**$ 8,436**	**$ 8,153**	**$ 7,869**	**$ 8,356**	**$ 8,072**	**$ 704**	**$ 704**	**$ 704**	**$ 704**	**$ 704**	**$ 52,974**	**105**
60	**Power Purchases**	**$ 10,544**	**$ 14,617**	**$ 18,664**	**$ 10,594**	**$ 10,446**	**$ 10,528**	**$ 8,464**	**$ 704**	**$ 704**	**$ 2,308**	**$ 4,525**	**$ 7,704**	**$ 99,802**	**335**

Table 4.2 - Revenue at Proposed Rates

	B C D E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.2 - Revenue at Proposed Rates**													**2013**	
2	**Category**	**201210**	**201211**	**201212**	**201301**	**201302**	**201303**	**201304**	**201305**	**201306**	**201307**	**201308**	**201309**	**$ (000's)**	**aMW**
3	PF Full Service														
4	PF Partial Service														
5	PF Block Service														
6	PF Slice														
7	Irrigation Mitigation														
8	Low Density Discount (current rates only)														
9	**PF customers (Subscription) sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
10	Composite Revenue	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 2,276,003	6,959
11	Non-Slice Revenue	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (327,962)	-
12	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	Load Shaping Revenue	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 24,123	54
14	Demand Revenue	$ 2,151	$ (6,442)	$ 18,956	$ 16,756	$ 22,068	$ 16,353	$ 25,134	$ (45,039)	$ (26,070)	$ (25,126)	$ (2,070)	$ (7,927)	$ (11,256)	(17)
15	Irrig. Mit.	$ 4,643	$ 3,814	$ 7,876	$ 7,173	$ 4,851	$ 4,971	$ 5,048	$ 3,922	$ 3,612	$ 5,488	$ 6,131	$ 3,739	$ 61,269	-
16	Low Density Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,976)	$ (4,447)	$ (5,122)	$ (4,203)	$ (2,557)	$ (19,305)	-
17	Tier 2	$ (2,666)	$ (2,278)	$ (3,110)	$ (2,915)	$ (2,997)	$ (2,835)	$ (3,247)	$ (1,919)	$ (2,518)	$ (2,681)	$ (3,138)	$ (2,640)	$ (32,944)	-
18	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 317	-
19	**PF customers (CHWM) sub-total**	**$ 168,502**	**$ 159,467**	**$ 188,096**	**$ 185,388**	**$ 188,295**	**$ 182,864**	**$ 191,308**	**$ 118,362**	**$ 134,950**	**$ 136,933**	**$ 161,093**	**$ 154,988**	**$ 1,970,246**	**6,996**
20	**DSIs sub-total**	**$ 9,048**	**$ 8,818**	**$ 9,674**	**$ 9,375**	**$ 8,753**	**$ 9,369**	**$ 8,623**	**$ 7,856**	**$ 7,567**	**$ 9,464**	**$ 10,104**	**$ 9,683**	**$ 108,334**	**341**
21	**FPS sub-total**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 148**	**$ 1,778**	**8**
22	**Short-term market sales sub-total**	**$ 11,749**	**$ 14,911**	**$ 20,431**	**$ 41,434**	**$ 33,885**	**$ 42,391**	**$ 66,881**	**$ 76,527**	**$ 61,193**	**$ 50,024**	**$ 26,561**	**$ 13,665**	**$ 459,653**	**1,652**
23	**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**	**62**
24	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**505**
25	**Renewable Energy Certificates sub-total**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 236**	**$ 2,836**	**40**
26	Network Wind Integration & Shaping	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 173	$ 2,078	-
27	Miscellaneous Credits (incl. GTA)	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 285	$ 3,420	-
28	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
29	**Other Sales sub-total**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 458**	**$ 5,498**	**-**
30	**Gross Sales**	**$ 190,182**	**$ 189,932**	**$ 225,096**	**$ 243,082**	**$ 237,308**	**$ 238,493**	**$ 270,587**	**$ 203,667**	**$ 204,638**	**$ 197,345**	**$ 198,663**	**$ 179,218**	**$ 2,578,210**	**9,605**
31	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
32	Irrigation Pumping Power	$ 79	$ 1	$ 1	$ 1	$ 1	$ 9	$ 84	$ 181	$ 216	$ 275	$ 256	$ 181	$ 1,284	174
33	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
34	Downstream Benefits	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 370	$ 4,435	-
35	US Bureau of Reclamation	$ -	$ 96	$ 101	$ 99	$ 101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397	1
36	**Miscellaneous Revenues**	**$ 2,134**	**$ 2,151**	**$ 2,157**	**$ 2,154**	**$ 2,157**	**$ 2,063**	**$ 2,138**	**$ 2,236**	**$ 2,270**	**$ 2,330**	**$ 2,311**	**$ 2,235**	**$ 26,335**	**178**
37	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
38	Wind Balancing Reserve / Variable Energy Resource Balancing Service -Wind	$ 4,845	$ 4,845	$ 5,252	$ 5,252	$ 5,345	$ 5,345	$ 5,345	$ 5,345	$ 5,345	$ 5,406	$ 5,547	$ 5,547	$ 63,417	-
39	Committed Intra-Hour Scheduling Pilot Adjustment	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (251)	$ (3,011)	-
40	VERBS Reserve Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 78	-
41	Dispatchable Energy Reseource Balancing Service Reserve	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 479	$ 5,753	-
42	Operating Reserve - Spinning	$ 1,901	$ 1,898	$ 2,162	$ 2,136	$ 1,900	$ 2,056	$ 2,006	$ 2,068	$ 2,145	$ 2,224	$ 2,157	$ 1,915	$ 24,570	-
43	Operating Reserve - Supplemental	$ 1,616	$ 1,613	$ 1,837	$ 1,816	$ 1,615	$ 1,747	$ 1,705	$ 1,757	$ 1,823	$ 1,890	$ 1,833	$ 1,628	$ 20,880	-
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	Generation Imbalance/Energy Imbalance/Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Contingency Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
49	COE/Reclamation Network/Delivery Facilities Segmentation	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 599	$ 7,183	-
50	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
51	**Generation Inputs / Inter-business line**	**$ 10,213**	**$ 10,208**	**$ 11,103**	**$ 11,055**	**$ 10,711**	**$ 10,999**	**$ 10,906**	**$ 11,020**	**$ 11,164**	**$ 11,371**	**$ 11,388**	**$ 10,941**	**$ 131,078**	**9**
52	4(h)(10)(c)	$ 10,966	$ 8,749	$ 10,658	$ 10,767	$ 9,446	$ 8,717	$ 6,566	$ 5,625	$ 5,865	$ 5,187	$ 6,112	$ 7,189	$ 95,847	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 11,350**	**$ 9,132**	**$ 11,041**	**$ 11,150**	**$ 9,830**	**$ 9,100**	**$ 6,950**	**$ 6,008**	**$ 6,248**	**$ 5,571**	**$ 6,495**	**$ 7,572**	**$ 100,447**	**-**
55	Augmentation Purchases	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 5,513	$ 66,150	176
56	ERE augmentation purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57	**Augmentation Power Purchase sub-total**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 5,513**	**$ 66,150**	**176**
58	**Balancing Power Purchase sub-total**	**$ 5,614**	**$ 4,637**	**$ 8,029**	**$ 800**	**$ 1,501**	**$ 998**	**$ 4**	**$ -**	**$ -**	**$ 1,322**	**$ 2,215**	**$ 4,441**	**$ 29,559**	**140**
59	**Other Power Purchase sub-total**	**$ 1,952**	**$ 8,750**	**$ 9,320**	**$ 9,037**	**$ 8,753**	**$ 9,603**	**$ 9,320**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 66,492**	**140**
60	**Power Purchases**	**$ 13,078**	**$ 18,899**	**$ 22,861**	**$ 15,350**	**$ 15,766**	**$ 16,114**	**$ 14,836**	**$ 7,464**	**$ 7,464**	**$ 8,786**	**$ 9,679**	**$ 11,905**	**$ 162,201**	**456**

Table 4.3 - Subscription Contract Revenue - FY 2011

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.3 – Subscription Contract Revenue – FY 2011**														
2	Table shows calculation of Subscription Revenue at current rates.														
3			**FY 2011**												
4		**Load Following - Full Service**	**10/1/2010**	**11/1/2010**	**12/1/2010**	**1/1/2011**	**2/1/2011**	**3/1/2011**	**4/1/2011**	**5/1/2011**	**6/1/2011**	**7/1/2011**	**8/1/2011**	**9/1/2011**	**Total**
5	**A)**	HLH energy	877,692	947,670	1,126,405	1,109,257	975,374	964,768	886,790	786,453	774,940	812,037	840,793	842,955	10,945,134
6	**B)**	LLH energy	568,348	672,330	798,861	790,249	662,487	627,086	584,018	544,285	471,313	544,269	504,884	574,505	7,342,635
7	**C)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
8	**D)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
9	**E)**	Revenues (A * C) + (B * D)	$ 40,645,993	$ 48,171,967	$ 59,869,903	$ 49,881,491	$ 43,926,304	$ 40,053,519	$ 34,481,210	$ 25,628,328	$ 20,451,258	$ 29,743,148	$ 34,972,247	$ 38,731,963	$ 466,557,331
10	**F)**	Stepped Rate adder (MWh)	259,217	282,811	332,167	328,736	279,912	276,639	267,879	235,098	206,754	235,368	232,212	275,932	
11	**G)**	Stepped Rate Revenues (F*0.62)	$ 160,715	$ 175,343	$ 205,944	$ 203,816	$ 173,545	$ 171,516	$ 166,085	$ 145,761	$ 128,187	$ 145,928	$ 143,971	$ 171,078	$ 1,991,890
12															
13	**H)**	Demand (KWh)	2,728,000	2,799,000	3,242,000	3,298,000	3,196,000	2,826,000	2,570,000	2,187,000	2,234,000	2,580,000	2,472,000	2,298,000	32,430,000
14	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
15	**J)**	Demand Revenue (H * I)	$ 5,592,400	$ 6,129,810	$ 7,456,600	$ 6,464,080	$ 6,360,040	$ 5,228,100	$ 4,471,800	$ 3,149,280	$ 2,948,880	$ 4,153,800	$ 4,672,080	$ 4,504,080	$ 61,130,950
16															
17	**K)**	Total Retail Load	1,475,296	1,645,316	1,949,388	1,920,586	1,658,077	1,614,835	1,496,040	1,514,648	1,497,025	1,636,547	1,591,450	1,444,607	19,443,815
18	**L)**	Load Variance Rate	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	
19	**M)**	Load Variance Revenue (K * L)	$ 722,895	$ 806,205	$ 955,200	$ 941,087	$ 812,458	$ 791,269	$ 733,060	$ 742,178	$ 733,542	$ 801,908	$ 779,811	$ 707,857	$ 9,527,469
20															
21	**N)**	Low Density Discount %	-2.96%	-2.86%	-2.92%	-2.90%	-2.89%	-3.03%	-3.19%	-3.29%	-3.33%	-3.23%	-3.09%	-3.31%	
22	**O)**	Low Density Discount (E + G + J + M) * L	$ (1,396,720)	$ (1,579,326)	$ (2,002,090)	$ (1,665,453)	$ (1,482,303)	$ (1,403,365)	$ (1,272,999)	$ (974,635)	$ (808,165)	$ (1,123,887)	$ (1,252,644)	$ (1,462,061)	$ (16,423,648)
23															
24	**P)**	Total Full Service Revenue (E + G + J + M + O)	$ 45,725,282	$ 53,703,998	$ 66,485,557	$ 55,825,022	$ 49,790,044	$ 44,841,039	$ 38,579,155	$ 28,690,911	$ 23,453,702	$ 33,720,898	$ 39,315,465	$ 42,652,917	$ 522,783,991
25	**Q)**	**Total Full Service Revenue (adjusted for actuals)**	**$ 42,718,440**	**$ 54,514,204**	**$ 62,787,511**	**$ 52,483,001**	**$ 49,463,823**	$ 44,841,039	$ 38,579,155	$ 28,690,911	$ 23,453,702	$ 33,720,898	$ 39,315,465	$ 42,652,917	**$ 513,221,066**
26															
27		*Ties to Table 4.1, Revenue at Current Rates, and Table 4.2, Revenue at Proposed Rates, line 3 (FY 2011 only)*													
28															
29		**Load Following - Partial Service**	**10/1/2010**	**11/1/2010**	**12/1/2010**	**1/1/2011**	**2/1/2011**	**3/1/2011**	**4/1/2011**	**5/1/2011**	**6/1/2011**	**7/1/2011**	**8/1/2011**	**9/1/2011**	**Total**
30	**A)**	HLH energy	616,392	685,267	767,971	747,895	659,716	665,387	610,636	559,458	578,089	603,976	646,998	576,722	7,672,125
31	**B)**	LLH energy	397,415	478,350	530,080	522,601	434,118	424,438	398,155	410,945	367,183	419,812	397,235	391,015	5,129,158
32	**C)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
33	**D)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
34	**E)**	Revenues (A * C) + (B * D)	$ 28,505,392	$ 34,642,535	$ 40,444,818	$ 33,412,541	$ 29,407,670	$ 27,458,343	$ 23,667,678	$ 18,593,251	$ 15,421,339	$ 22,392,102	$ 27,097,590	$ 26,450,433	$ 327,493,693
35	**F)**	Stepped Rate adder (MWh)	93,167	96,631	107,929	108,574	91,298	90,410	82,231	74,829	83,745	91,399	86,680	87,433	
36	**G)**	Stepped Rate Revenues (F*0.62)	$ 57,764	$ 59,911	$ 66,916	$ 67,316	$ 56,605	$ 56,054	$ 50,983	$ 46,394	$ 51,922	$ 56,667	$ 53,742	$ 54,208	$ 678,482
37															
38	**H)**	Demand (KWh)	1,833,000	1,992,000	2,205,000	2,206,000	2,121,000	1,855,000	1,760,000	1,565,000	1,518,000	1,697,000	1,666,000	1,522,000	21,940,000
39	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
40	**J)**	Demand Revenue (H * I)	$ 3,757,650	$ 4,362,480	$ 5,071,500	$ 4,323,760	$ 4,220,790	$ 3,431,750	$ 3,062,400	$ 2,253,600	$ 2,003,760	$ 2,732,170	$ 3,148,740	$ 2,983,120	$ 41,351,720
41															
42	**K)**	Total Retail Load	1,251,844	1,403,949	1,558,931	1,521,240	1,324,155	1,329,153	1,237,056	1,201,431	1,163,087	1,245,916	1,250,323	1,184,417	15,671,502
43	**L)**	Load Variance Rate	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	
44	**M)**	Load Variance Revenue (K * L)	$ 613,404	$ 687,935	$ 763,876	$ 745,408	$ 648,836	$ 651,285	$ 606,157	$ 588,701	$ 569,913	$ 610,499	$ 612,658	$ 580,364	$ 7,679,036
45															
46	**N)**	Low Density Discount %	-0.53%	-0.48%	-0.48%	-0.50%	-0.48%	-0.50%	-0.48%	-0.23%	-0.12%	-0.44%	-0.50%	-0.73%	
47	**O)**	Low Density Discount (E + G + J + M) * L	$ (174,474)	$ (190,696)	$ (224,533)	$ (192,743)	$ (165,719)	$ (157,967)	$ (131,938)	$ (50,311)	$ (21,707)	$ (113,281)	$ (155,652)	$ (218,825)	$ (1,797,846)
48															
49	**P)**	Total Partial Service Revenue (E + G + J + M + O)	$ 32,759,735	$ 39,562,165	$ 46,122,578	$ 38,356,282	$ 34,168,182	$ 31,439,465	$ 27,255,281	$ 21,431,635	$ 18,025,227	$ 25,678,157	$ 30,757,078	$ 29,849,301	$ 375,405,085
50	**Q)**	**Total Partial Service Revenue (adjusted for actuals)**	**$ 31,540,135**	**$ 38,389,017**	**$ 43,049,868**	**$ 36,978,324**	**$ 35,414,804**	$ 31,439,465	$ 27,255,281	$ 21,431,635	$ 18,025,227	$ 25,678,157	$ 30,757,078	$ 29,849,301	**$ 369,808,292**
51		*Ties to Table 4.1, Revenue at Current Rates, and Table 4.2, Revenue at Proposed Rates, line 4 (FY 2011 only)*													
52															
53		**Block Service**	**10/1/2010**	**11/1/2010**	**12/1/2010**	**1/1/2011**	**2/1/2011**	**3/1/2011**	**4/1/2011**	**5/1/2011**	**6/1/2011**	**7/1/2011**	**8/1/2011**	**9/1/2011**	**Total**
54	**A)**	HLH energy	689,222	796,269	933,948	914,037	866,966	904,463	725,374	565,379	535,614	558,239	624,974	718,375	8,804,930
55	**B)**	LLH energy	519,900	621,150	709,868	750,817	625,585	631,919	512,182	462,977	375,488	454,461	435,873	555,929	6,630,739
56	**C)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
57	**D)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
58	**E)**	Revenues (A * C) + (B * D)	$ 33,611,362	$ 41,849,706	$ 50,858,936	$ 43,241,151	$ 39,840,422	$ 38,457,350	$ 28,858,713	$ 19,516,723	$ 14,661,919	$ 21,891,686	$ 27,288,281	$ 34,589,084	$ 394,665,333
59	**F)**	Stepped Rate adder (MWh)	252,960	314,356	383,160	384,648	356,832	387,103	329,040	300,576	259,920	272,304	257,424	254,160	
60	**G)**	Stepped Rate Revenues (F*0.62)	$ 156,835	$ 194,901	$ 237,559	$ 238,482	$ 221,236	$ 240,004	$ 204,005	$ 186,357	$ 161,150	$ 168,829	$ 159,603	$ 157,579	$ 2,326,540
61															
62	**H)**	Demand (KWh)	1,829,000	2,150,000	2,439,000	2,412,000	2,411,000	2,215,000	1,828,000	1,367,000	1,328,000	1,448,000	1,523,000	1,832,000	22,782,000
63	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
64	**J)**	Demand Revenue (H * I)	$ 3,749,450	$ 4,708,500	$ 5,609,700	$ 4,727,520	$ 4,797,890	$ 4,097,750	$ 3,180,720	$ 1,968,480	$ 1,752,960	$ 2,331,280	$ 2,878,470	$ 3,590,720	$ 43,393,440
65															
66	**K)**	Low Density Discount %	-0.74%	-0.68%	-0.69%	-0.70%	-0.68%	-0.63%	-1.15%	-1.27%	-1.23%	-0.95%	-0.72%	-0.82%	
67	**L)**	Low Density Discount (E + H + K) * L	$ (276,601)	$ (318,570)	$ (392,006)	$ (337,137)	$ (303,486)	$ (268,303)	$ (372,099)	$ (275,350)	$ (204,128)	$ (230,535)	$ (219,370)	$ (312,475)	$ (2,960,170)
68															
69	**M)**	Total Block Service Revenue (E + G + J + L)	$ 37,241,046	$ 46,434,537	$ 56,314,189	$ 47,870,016	$ 44,556,062	$ 42,526,801	$ 31,871,338	$ 21,396,210	$ 16,371,901	$ 24,161,259	$ 30,106,984	$ 38,024,908	$ 436,875,252
70	**N)**	**Total Block Service Revenue (adjusted for actuals)**	**$ 37,168,015**	**$ 46,792,704**	**$ 56,659,441**	**$ 48,281,258**	**$ 44,355,018**	$ 42,526,801	$ 31,871,338	$ 21,396,210	$ 16,371,901	$ 24,161,259	$ 30,106,984	$ 38,024,908	**$ 437,715,837**
71															
72		*Ties to Table 4.1, Revenue at Current Rates, and Table 4.2, Revenue at Proposed Rates, line 5 (FY 2011 only)*													
73															
74		**Slice**													
75	**P)**	Slice Cost (per 1% of Slice)	$ 1,962,629.08												
76	**Q)**	Slice percentage	22.63%												
77	**R)**	Slice Revenue - gross (P * Q) * 100	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 44,409,978.31	$ 532,919,740
78															
79	**S)**	Low Density Discount %	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	-0.89%	
80	**T)**	Low Density Discount (R * S)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (395,949)	$ (4,751,384)
81															
82		Total Slice Revenue (R * T)	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 528,168,355
83		**Total Slice Revenue (adjusted for actuals)**	**$ 44,005,219**	**$ 44,005,319**	**$ 44,005,319**	**$ 44,012,819**	**$ 44,006,719**	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	$ 44,014,030	**$ 528,133,602**
84		*Ties to Table 4.1, Revenue at Current Rates, and Table 4.2, Revenue at Proposed Rates, line 6 (FY 2011 only)*													
85															
86	**U)**	Irrigation eligible loads	-	-	-	-	-	-	-	316,654	454,307	522,150	438,548		1,731,659
87		Implied rate (T / R)								$11.68	$8.76	$14.14	$17.83		
88	**V)**	Total Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	-	3,699,960	3,980,030	7,381,557	7,818,738	$ -	$ 22,880,285
89		**Total Irrigation Rate Discount (adjusted for actuals)**	**$ 9,699**	**$ 9,699**	**$ 9,699**	**$ 9,699**	**$ 9,699**	$ -	$ -	$ 3,699,960	$ 3,980,030	$ 7,381,557	$ 7,818,738	$ -	**$ 22,928,780**
90		*Ties to Table 4.1, Revenue at Current Rates, and Table 4.2, Revenue at Proposed Rates, line 7 (FY 2011 only)*													

Table 4.4 – Subscription Contract Revenue – FY 2012-2013

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.4 – Subscription Contract Revenue – FY 2012-2013**														
2	Table shows calculation of Subscription Revenue at current rates.														
3			**FY 2012**												
4		**Load Following**	**10/1/2011**	**11/1/2011**	**12/1/2011**	**1/1/2012**	**2/1/2012**	**3/1/2012**	**4/1/2012**	**5/1/2012**	**6/1/2012**	**7/1/2012**	**8/1/2012**	**9/1/2012**	**Total**
5	**A)**	HLH energy	1,280,100	1,372,627	1,640,930	1,600,316	1,422,531	1,398,066	1,285,097	1,275,830	1,339,267	1,425,340	1,438,465	1,237,607	16,716,177
6	**B)**	LLH energy	804,068	963,070	1,146,351	1,123,510	941,476	893,869	839,754	879,718	827,453	970,165	887,563	840,466	11,117,463
7	**C)**	HLH energy (Tier 2)	8,434	8,110	8,758	8,434	8,110	8,758	8,110	8,434	8,434	8,110	8,758	7,785	100,235
8	**D)**	LLH energy (Tier 2)	7,160	7,002	6,835	7,160	6,478	6,814	6,981	7,160	6,656	7,484	6,835	7,305	83,870
9	**E)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
10	**F)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
11	**G)**	Revenues (A+C)*E + (B+D)*F	$ 59,139,215	$ 69,953,533	$ 87,252,342	$ 72,011,872	$ 63,914,345	$ 58,122,982	$ 50,190,285	$ 41,821,187	$ 35,719,866	$ 52,807,762	$ 60,737,540	$ 57,199,027	$ 708,869,959
12															
13	**H)**	Demand (KW)	3,985,289	4,107,822	4,963,391	4,776,266	4,655,511	4,228,655	3,885,145	3,393,819	3,457,902	3,831,044	3,760,804	3,405,438	48,451,086
14	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
15	**J)**	Demand Revenue (H * I)	$ 8,169,842	$ 8,996,130	$ 11,415,799	$ 9,361,481	$ 9,264,467	$ 7,823,012	$ 6,760,152	$ 4,887,099	$ 4,564,431	$ 6,167,981	$ 7,107,920	$ 6,674,658	$ 91,192,973
16															
17	**K)**	Total Retail Load (HLH)	1,308,322	1,396,295	1,664,935	1,621,446	1,444,422	1,421,736	1,310,288	1,306,594	1,372,159	1,454,445	1,469,000	1,262,610	17,032,253
18	**L)**	Total Retail Load (LLH)	827,644	983,305	1,166,039	1,142,355	958,753	911,993	861,156	905,068	852,656	996,695	910,959	863,398	11,380,021
19	**M)**	Load Variance Rate	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	
20	**N)**	Load Variance Revenue (K + L)*M	$ 1,046,624	$ 1,166,004	$ 1,387,177	$ 1,354,262	$ 1,177,556	$ 1,143,527	$ 1,064,008	$ 1,083,714	$ 1,090,159	$ 1,201,058	$ 1,166,180	$ 1,041,744	$ 13,922,014
21															
22	**O)**	**Total Load Following Revenue (G + J + N)**	**$ 68,355,681**	**$ 80,115,668**	**$ 100,055,319**	**$ 82,727,616**	**$ 74,356,368**	**$ 67,089,521**	**$ 58,014,445**	**$ 47,792,001**	**$ 41,374,456**	**$ 60,176,802**	**$ 69,011,640**	**$ 64,915,430**	**$ 813,984,946**
23		*Ties to Table 4.1, Revenue at Current Rates, line 3 (FY 2012-2013 only)*													
24															
25		**Slice Block**													
26	**A)**	HLH energy	684,644	813,330	977,237	954,922	820,754	854,633	660,952	597,045	554,852	630,730	682,021	634,231	8,865,350
27	**B)**	LLH energy	539,816	652,698	705,782	752,919	607,358	615,257	528,761	470,747	405,469	542,427	492,571	554,952	6,868,755
28	**C)**	HLH energy (Tier 2)	0	0	0	0	0	0	0	0	0	0	0	0	-
29	**D)**	LLH energy (Tier 2)	0	0	0	0	0	0	0	0	0	0	0	0	-
30	**E)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
31	**F)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
32	**G)**	Revenues (A+C)*E + (B+D)*F	$ 33,925,845	$ 43,191,970	$ 52,267,509	$ 44,499,739	$ 38,044,555	$ 36,712,717	$ 27,473,114	$ 20,333,052	$ 15,363,202	$ 25,255,297	$ 30,140,017	$ 32,066,695	$ 399,273,712
33															
34	**H)**	Demand (KW)	1,645,780	2,033,326	2,262,122	2,295,486	2,051,884	1,978,317	1,652,379	1,435,204	1,333,778	1,576,824	1,578,752	1,651,642	21,495,494
35	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
36	**J)**	Demand Revenue (H * I)	$ 3,373,849	$ 4,452,984	$ 5,202,881	$ 4,499,152	$ 4,083,249	$ 3,659,887	$ 2,875,139	$ 2,066,694	$ 1,760,587	$ 2,538,687	$ 2,983,841	$ 3,237,218	$ 40,734,168
37															
38		**Total Slice Block Revenue (G + J)**	**$ 37,299,694**	**$ 47,644,954**	**$ 57,470,390**	**$ 48,998,891**	**$ 42,127,804**	**$ 40,372,604**	**$ 30,348,254**	**$ 22,399,746**	**$ 17,123,789**	**$ 27,793,983**	**$ 33,123,858**	**$ 35,303,913**	**$ 440,007,880**
39		*Ties to Table 4.1, Revenue at Current Rates, line 5 (FY 2012-2013 only)*													
40															
41		T1SFCO (aMW)	6998												
42	**P)**	Slice Cost (per 1% of Slice)	$ 1,962,525.00												
43	**Q)**	Slice percentage	26.85%												
44															
45		**Total Slice Revenue (P * Q * 100)**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 636,494,900**
46		*Ties to Table 4.1, Revenue at Current Rates, line 6 (FY 2012-2013 only)*													
47															
48	**R)**	Irrigation eligible loads	-	-	-	-	-	-	-	290,041	433,464	499,210	409,669	249,220	1,881,605
49	**S)**	Average irrigation rate discount	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	
50		**Total Irrigation Rate Discount (R * S)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (2,030,385)**	**$ (3,034,391)**	**$ (3,494,641)**	**$ (2,867,821)**	**$ (1,744,626)**	**$ (13,171,865)**
51		*Ties to Table 4.1, Revenue at Current Rates, line 7 (FY 2012-2013 only)*													
52															
53	**T)**	Low Density Discount%	-3.25%	-3.18%	-3.29%	-3.21%	-3.18%	-3.20%	-3.26%	-3.10%	-3.61%	-3.69%	-3.60%	-3.46%	
54		**Total Low Density Discount (O * T)**	**$ (2,221,498)**	**$ (2,548,108)**	**$ (3,288,699)**	**$ (2,654,538)**	**$ (2,367,942)**	**$ (2,147,131)**	**$ (1,892,060)**	**$ (1,483,702)**	**$ (1,491,779)**	**$ (2,218,494)**	**$ (2,482,307)**	**$ (2,243,092)**	**$ (27,039,350)**
55		*Ties to Table 4.1, Revenue at Current Rates, line 8 (FY 2012-2013 only)*													
56															
57															
58															

Table 4.4 – Subscription Contract Revenue – FY 2012-2013

	A	B	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
1	**Table 4.4 – Subscription Contract Revenue – FY 2012-2013**														
2	Table shows calculation of Subscription Revenue at current rates.														
3			**FY 2013**												
4		**Load Following**	**10/1/2012**	**11/1/2012**	**12/1/2012**	**1/1/2013**	**2/1/2013**	**3/1/2013**	**4/1/2013**	**5/1/2013**	**6/1/2013**	**7/1/2013**	**8/1/2013**	**9/1/2013**	**Total**
5	**A)**	HLH energy	1,294,092	1,385,719	1,647,286	1,623,140	1,414,746	1,404,594	1,303,160	1,288,759	1,344,428	1,449,351	1,452,055	1,250,247	16,857,578
6	**B)**	LLH energy	797,490	956,358	1,149,366	1,102,931	924,851	898,730	824,777	874,542	829,244	957,113	882,699	833,713	11,031,815
7	**C)**	HLH energy (Tier 2)	23,702	21,946	21,946	22,824	21,068	22,853	22,824	22,824	21,946	22,824	23,702	21,068	269,526
8	**D)**	LLH energy (Tier 2)	18,359	18,814	20,115	19,237	16,922	19,205	17,880	19,237	18,758	19,237	18,359	19,636	225,758
9	**E)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
10	**F)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
11	**G)**	Revenues (A+C)*E + (B+D)*F	$ 60,164,589	$ 70,980,258	$ 88,353,519	$ 72,933,914	$ 63,937,185	$ 59,058,470	$ 50,977,919	$ 42,528,476	$ 36,239,495	$ 53,735,857	$ 61,700,877	$ 58,101,904	$ 718,712,465
12															
13	**H)**	Demand (KW)	4,050,066	4,366,587	5,231,816	5,027,105	4,918,969	4,447,159	4,066,708	3,687,188	3,721,208	4,125,126	4,015,129	3,640,812	51,297,873
14	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
15	**J)**	Demand Revenue (H * I)	$ 8,302,635	$ 9,562,826	$ 12,033,177	$ 9,853,126	$ 9,788,748	$ 8,227,244	$ 7,076,072	$ 5,309,551	$ 4,911,995	$ 6,641,453	$ 7,588,594	$ 7,135,992	$ 96,431,411
16															
17	**K)**	Total Retail Load (HLH)	1,343,286	1,419,456	1,679,008	1,654,829	1,446,252	1,439,350	1,342,172	1,331,578	1,388,098	1,491,523	1,495,876	1,286,500	17,317,927
18	**L)**	Total Retail Load (LLH)	835,233	1,000,786	1,196,766	1,146,590	963,008	941,150	866,535	923,124	877,812	1,005,868	928,100	879,530	11,564,503
19	**M)**	Load Variance Rate	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	
20	**N)**	Load Variance Revenue (K + L)*M	$ 1,067,474	$ 1,185,918	$ 1,409,129	$ 1,372,695	$ 1,180,537	$ 1,166,445	$ 1,082,266	$ 1,104,804	$ 1,110,296	$ 1,223,722	$ 1,187,748	$ 1,061,355	$ 14,152,391
21															
22	**O)**	**Total Load Following Revenue (G + J + N)**	**$ 69,534,699**	**$ 81,729,002**	**$ 101,795,825**	**$ 84,159,736**	**$ 74,906,471**	**$ 68,452,160**	**$ 59,136,257**	**$ 48,942,831**	**$ 42,261,785**	**$ 61,601,032**	**$ 70,477,219**	**$ 66,299,251**	**$ 829,296,267**
23		*Ties to Table 4.1, Revenue at Current Rates, line 3 (FY 2012-2013 only)*													
24															
25		**Slice Block**													
26	**A)**	HLH energy	724,137	829,161	922,692	974,100	832,379	839,007	700,292	609,182	544,871	668,823	695,199	646,018	8,985,860
27	**B)**	LLH energy	522,988	665,402	793,515	768,041	624,284	659,508	511,752	480,317	435,897	527,341	502,088	565,266	7,056,397
28	**C)**	HLH energy (Tier 2)	0	0	0	0	0	0	0	0	0	0	0	0	-
29	**D)**	LLH energy (Tier 2)	0	0	0	0	0	0	0	0	0	0	0	0	-
30	**E)**	HLH rate	31.41	33.5	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.7	
31	**F)**	LLH rate	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84	
32	**G)**	Revenues (A+C)*E + (B+D)*F	$ 34,779,089	$ 44,032,667	$ 52,610,951	$ 45,393,461	$ 38,763,894	$ 37,185,321	$ 28,188,635	$ 20,746,399	$ 15,486,318	$ 25,919,839	$ 30,722,370	$ 32,662,657	$ 406,491,601
33															
34	**H)**	Demand (KW)	1,676,243	2,072,903	2,306,729	2,341,588	2,167,654	2,016,843	1,683,394	1,464,380	1,362,177	1,607,747	1,609,256	1,682,338	21,991,251
35	**I)**	Demand rate (KW)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
36	**J)**	Demand Revenue (H * I)	$ 3,436,298	$ 4,539,657	$ 5,305,477	$ 4,589,512	$ 4,313,631	$ 3,731,160	$ 2,929,106	$ 2,108,707	$ 1,798,074	$ 2,588,473	$ 3,041,494	$ 3,297,382	$ 41,678,970
37															
38		**Total Slice Block Revenue (G + J)**	**$ 38,215,387**	**$ 48,572,324**	**$ 57,916,428**	**$ 49,982,973**	**$ 43,077,525**	**$ 40,916,480**	**$ 31,117,741**	**$ 22,855,106**	**$ 17,284,391**	**$ 28,508,312**	**$ 33,763,864**	**$ 35,960,040**	**$ 448,170,571**
39		*Ties to Table 4.1, Revenue at Current Rates, line 5 (FY 2012-2013 only)*													
40															
41		T1SFCO (aMW)													
42	**P)**	Slice Cost (per 1% of Slice)													
43	**Q)**	Slice percentage													
44															
45		**Total Slice Revenue (P * Q * 100)**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 53,041,242**	**$ 636,494,900**
46		*Ties to Table 4.1, Revenue at Current Rates, line 6 (FY 2012-2013 only)*													
47															
48	**R)**	Irrigation eligible loads	-	-	-	-	-	-	-	290,041	433,464	499,210	409,669	249,220	1,881,605
49	**S)**	Average irrigation rate discount	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	($7.00)	
50		**Total Irrigation Rate Discount (R * S)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (2,030,385)**	**$ (3,034,391)**	**$ (3,494,641)**	**$ (2,867,821)**	**$ (1,744,626)**	**$ (13,171,865)**
51		*Ties to Table 4.1, Revenue at Current Rates, line 7 (FY 2012-2013 only)*													
52															
53	**T)**	Low Density Discount%	-3.34%	-3.27%	-3.37%	-3.30%	-3.30%	-3.29%	-3.36%	-3.60%	-3.70%	-3.79%	-3.70%	-3.55%	
54		**Total Low Density Discount (O * T)**	**$ (2,323,484)**	**$ (2,670,872)**	**$ (3,433,983)**	**$ (2,775,328)**	**$ (2,468,754)**	**$ (2,249,887)**	**$ (1,984,476)**	**$ (1,762,528)**	**$ (1,564,803)**	**$ (2,333,651)**	**$ (2,606,375)**	**$ (2,356,385)**	**$ (28,530,526)**
55		*Ties to Table 4.1, Revenue at Current Rates, line 8 (FY 2012-2013 only)*													
56															
57															
58															

Table 4.5 – Composite and Non-slice revenue – FY 2012-2013

	A	B	C	D	E	F	G
1	**Table 4.5 – Composite and Non-slice revenue – FY 2012-2013**						
2	Table shows calculation of CHWM revenues at proposed rates.						
3							
4	**Billing Determinants**	**FY 2012**		**FY 2013**		**Rate Period**	
5	**TOCA...**	95.997110	A)	97.157020	A)	96.577065	
6	**Non-slice TOCA..**	69.143170	B)	70.303080	B)	69.723125	
7	**Slice Percentage...**	26.853940		26.853940		26.853940	
8							
9	**Annual TRM Rates ($000)**	**FY 2012**		**FY 2013**		**Rate Period**	
10	**Composite...**	$ 23,117		$ 23,732		$ 23,426	C)
11	**Non-Slice...**	$ (4,328)		$ (4,996)		$ (4,665)	D)
12	**Slice...**	$ -		$ -		$ -	
13							
14	**Yearly Revenues (Yearly TOCA * Rate Period rate)**	**FY 2012**		**FY 2013**			
15	**Composite (A * C)...**	$ 2,248,831	E)	$ 2,276,003	E)		
16	**Non-Slice (B * D)...**	$ (322,551)	E)	$ (327,962)	E)		
17	**Slice...**	$ -		$ -			
18							
19	**Monthly Revenues (Yearly Revenues / 12)**	**FY 2012**		**FY 2013**			
20	**Composite (E / 12)...**	$ 187,403		$ 189,667			
21	**Non-Slice (E / 12)...**	$ (26,879)		$ (27,330)			
22	**Slice...**	$ -		$ -			
23							
24	*Ties to Table 4.2, Revenue at Proposed Rates, lines 10-11*						

Table 4.6 – Load Shaping and Demand revenue – FY 2012-2013

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.6 – Load Shaping and Demand revenue – FY 2012-2013**														
2	Table shows calculation of CHWM revenues at proposed rates.														
3															
4															
5	**FY 2012**		**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Total**
6	Load Shaping HLH (MWh)	A)	(94,042)	(248,579)	161,064	136,571	223,528	241,919	393,468	(994,666)	(599,801)	(724,284)	(186,213)	(294,287)	
7	Load Shaping LLH (MWh)	B)	174,936	100,648	368,441	338,320	275,901	202,414	325,253	(383,374)	(154,194)	153,428	169,599	125,263	
8	Load Shaping HLH Rate ($/MWh)	C)	$ 37.86	$ 38.37	$ 41.10	$ 40.03	$ 40.93	$ 39.57	$ 37.53	$ 35.06	$ 35.97	$ 42.07	$ 44.35	$ 43.45	
9	Load Shaping LLH Rate ($/MWh)	D)	$ 31.20	$ 31.40	$ 33.39	$ 31.70	$ 33.17	$ 32.33	$ 30.41	$ 24.40	$ 23.02	$ 29.91	$ 32.15	$ 33.59	
10	Load Shaping Revenue (A * C) + (B * D)		$ 1,897,569	$ (6,377,622)	$ 18,921,999	$ 16,191,654	$ 18,300,656	$ 16,116,797	$ 24,657,794	$ (44,227,326)	$ (25,124,374)	$ (25,881,587)	$ (2,805,921)	$ (8,579,186)	$ (16,909,548)
11															
12	Demand (kW)	E)	404,624	389,557	900,108	595,038	520,155	608,701	437,157	443,798	505,235	409,717	550,674	340,587	
13	Demand Rate ($/kW-mo.)	F)	$ 9.18	$ 9.31	$ 9.97	$ 9.70	$ 9.92	$ 9.60	$ 9.10	$ 8.50	$ 8.72	$ 10.20	$ 10.75	$ 10.53	
14	Demand Revenue (E * F)		$ 3,714,448	$ 3,626,776	$ 8,974,077	$ 5,771,869	$ 5,159,938	$ 5,843,530	$ 3,978,129	$ 3,772,283	$ 4,405,649	$ 4,179,113	$ 5,919,746	$ 3,586,381	$ 58,931,937
15															
16															
17															
18															
19	**FY 2013**		**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Total**
20	Load Shaping HLH (MWh)	A)	(61,266)	(252,673)	117,231	184,355	283,469	208,689	431,883	(1,012,850)	(641,839)	(689,850)	(177,054)	(286,437)	
21	Load Shaping LLH (MWh)	B)	143,284	103,611	423,419	295,791	315,502	250,403	293,504	(390,520)	(129,604)	130,271	179,848	134,525	
22	Load Shaping HLH Rate ($/MWh)	C)	$ 37.86	$ 38.37	$ 41.10	$ 40.03	$ 40.93	$ 39.57	$ 37.53	$ 35.06	$ 35.97	$ 42.07	$ 44.35	$ 43.45	
23	Load Shaping LLH Rate ($/MWh)	D)	$ 31.20	$ 31.40	$ 33.39	$ 31.70	$ 33.17	$ 32.33	$ 30.41	$ 24.40	$ 23.02	$ 29.91	$ 32.15	$ 33.59	
24	Load Shaping Revenue (A * C) + (B * D)		$ 2,150,909	$ (6,441,694)	$ 18,956,155	$ 16,756,329	$ 22,067,599	$ 16,353,366	$ 25,134,018	$ (45,039,186)	$ (26,070,420)	$ (25,125,600)	$ (2,070,210)	$ (7,926,999)	$ (11,255,732)
25															
26	Demand (kW)	E)	505,813	409,627	789,985	739,484	489,035	517,858	554,710	461,436	414,233	538,064	570,310	355,091	
27	Demand Rate ($/kW-mo.)	F)	$ 9.18	$ 9.31	$ 9.97	$ 9.70	$ 9.92	$ 9.60	$ 9.10	$ 8.50	$ 8.72	$ 10.20	$ 10.75	$ 10.53	
28	Demand Revenue (E * F)		$ 4,643,363	$ 3,813,627	$ 7,876,150	$ 7,172,995	$ 4,851,227	$ 4,971,437	$ 5,047,861	$ 3,922,206	$ 3,612,112	$ 5,488,253	$ 6,130,833	$ 3,739,108	$ 61,269,172
29															
30	*Ties to Table 4.2, Revenue at Proposed Rates, lines 13-14*														

Table 4.7 – Irrigation Rate Discount (IRD) – FY 2012-2013

Table 4.7 – Irrigation Rate Discount (IRD) – FY 2012-2013

Table shows calculation of IRD credit at proposed rates.

Irrigation Rate Discount		
IRD Percentage	37.06%	
Total Irrigation Load (MWh)	1,881,605	
RT1SC	7,181	
Annual NonSlice Dollar Amount	1,937,160,732	
Average Hours in Rate Period	8772	
Implied Discount ($/MWh)	$ 10.26	A)

FY 2012	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**		**TOTAL**
IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
IRD credit ($) (A * B)	$ (2,975,822)	$ (4,447,336)	$ (5,121,900)	$ (4,203,205)	$ (2,557,000)		**$ (19,305,263)**

FY2013	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**		**TOTAL**
IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
IRD credit ($) (A * B)	$ (2,975,822)	$ (4,447,336)	$ (5,121,900)	$ (4,203,205)	$ (2,557,000)		**$ (19,305,263)**

Ties to Table 4.2, Revenue at Proposed Rates, line 15

Table 4.8 – Low Density Discount (LDD) – FY 2012-2013

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.8 – Low Density Discount (LDD) – FY 2012-2013**														
2	Table shows calculation of LDD credit at proposed rates.														
3															
4	Low Density Discount														
5	Customer Charge LDD	**FY 2012**	**FY 2013**												
6	TOCA LDD Offset %..	1.56%	1.59%	**A)**											
7															
8	TRM Costs after Adjustments														
9	Composite...	$ 2,219,126	$ 2,305,709												
10	Non-Slice...	$ (299,273)	$ (351,240)												
11	Slice...	$ -	$ -												
12		$ 1,919,853	$ 1,954,469	**B)**											
13															
14	LDD discount - Composite portion (A * B).......................	$ 29,903.19	$ 31,126.98	**C)**											
15	LDD discount (Demand/Load Shaping portion)................	$ 1,864.90	$ 1,816.65	**D) below**											
16	**Total LDD discount (C + D)...**	**$ 31,768.09**	**$ 32,943.63**												
17															
18	**Demand and Load Shaping Discount Detail**														
19	**FY 2012**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**		
20	Demand BD (kW)	15,332	14,897	32,446	22,595	17,111	22,671	17,363	20,202	21,022	17,943	23,820	15,311		
21	Load Shaping BD HLH (MWh)	(3,063)	(9,086)	1,604	198	2,274	1,531	8,383	(18,631)	(6,121)	(8,391)	1,756	(4,217)		
22	Load Shaping BD LLH (MWh)	1,032	(2,051)	5,142	2,670	3,067	538	5,026	(7,197)	(57)	7,013	6,099	2,123		
23	Demand Rate	$ 9.18	$ 9.31	$ 9.97	$ 9.70	$ 9.92	$ 9.60	$ 9.10	$ 8.50	$ 8.72	$ 10.20	$ 10.75	$ 10.53		
24	Load Shaping Rate (HLH)	$ 37.86	$ 38.37	$ 41.10	$ 40.03	$ 40.93	$ 39.57	$ 37.53	$ 35.06	$ 35.97	$ 42.07	$ 44.35	$ 43.45		
25	Load Shaping Rate (LLH)	$ 31.20	$ 31.40	$ 33.39	$ 31.70	$ 33.17	$ 32.33	$ 30.41	$ 24.40	$ 23.02	$ 29.91	$ 32.15	$ 33.59		
26	LDD credit (Demand/Load Shaping portion)	$ 56,984	$ (274,315)	$ 561,091	$ 311,732	$ 364,557	$ 295,591	$ 625,416	$ (657,100)	$ (38,176)	$ 39,776	$ 530,016	$ 49,330	$ 1,864,902	
27														$ 1,864.90	**D)**
28	**FY 2013**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**		
29	Demand BD (kW)	19,135	15,198	30,821	27,436	17,494	20,761	21,461	21,728	18,442	22,972	25,161	16,222		
30	Load Shaping BD HLH (MWh)	(3,201)	(9,865)	832	(136)	2,920	710	8,457	(19,368)	(6,614)	(8,345)	1,692	(4,369)		
31	Load Shaping BD LLH (MWh)	568	(2,506)	5,222	1,894	3,323	412	4,620	(7,405)	40	6,831	6,170	1,943		
32	Demand Rate	$ 9.18	$ 9.31	$ 9.97	$ 9.70	$ 9.92	$ 9.60	$ 9.10	$ 8.50	$ 8.72	$ 10.20	$ 10.75	$ 10.53		
33	Load Shaping Rate (HLH)	$ 37.86	$ 38.37	$ 41.10	$ 40.03	$ 40.93	$ 39.57	$ 37.53	$ 35.06	$ 35.97	$ 42.07	$ 44.35	$ 43.45		
34	Load Shaping Rate (LLH)	$ 31.20	$ 31.40	$ 33.39	$ 31.70	$ 33.17	$ 32.33	$ 30.41	$ 24.40	$ 23.02	$ 29.91	$ 32.15	$ 33.59		
35	LDD credit(Demand/Load Shaping portion)	$ 72,223	$ (315,675)	$ 515,880	$ 320,719	$ 403,245	$ 240,721	$ 653,139	$ (675,062)	$ (76,191)	$ 87,535	$ 543,869	$ 46,250	$ 1,816,653	
36														$ 1,816.65	**D)**
37	**LDD credit is negative revenue*														
38	*Ties to Table 4.2, Revenue at Proposed Rates, line 16*														

Table 4.9 – Tier 2 revenue – FY 2012-2013

	A	B	C
1	**Table 4.9 – Tier 2 revenue – FY 2012-2013**		
2	Table shows calculation of CHWM revenues at proposed rates.		
3			
4	**Fiscal Year**	**FY2012**	
5	**Rate Period**	**WP-12**	**FY2013**
6			
7	Base Power Purchase Cost	$ 8,444,938	$ 22,276,330
8	Rate Design Components	$ 159,343	$ 705,445
9	Other Costs	$ -	$ -
10	Rate $/MWh	**$ 46.48**	**$ 48.69**
11	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (214,642)	$ (557,099)
12	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
13	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (42,574)	$ (108,570)
14	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (39,776)
15	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ 97,873	$ -
16	Total ST.1.2012_2014 Revenue	$ 8,603,691	$ 22,983,694
17			
18	Base Power Purchase Cost	$ -	$ 1,087,466
19	Rate Design Components	$ -	$ 53,346
20	Other Costs	$ -	$ -
21	Rate $/MWh	**$ -**	**$ 48.63**
22	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ -	$ (27,686)
23	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
24	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ -	$ (5,396)
25	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (20,263)
26	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
27	Total LG.1.2012_2028 Revenue	$ -	$ 1,140,825
28			
29	**Total Tier 2 Revenue Collection**	**$ 8,603,691**	**$ 24,124,519**
30			
31	Revenues are split evenly over 12 months of FY. Difference of ~$2K in 2013 numbers is due to rounding		
32			
33	*Ties to Table 4.2, Revenue at Proposed Rates, line 17*		
34			

Table 4.10 – Direct Service Industries (DSI) revenues – FY 2011-2013

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.10 – Direct Service Industries (DSI) revenues – FY 2011-2013**														
2	Table shows calculation of DSI revenues at current and proposed rates.														
4	**FY 2011**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
5	HLH rate (per MWh)	A)	31.92	33.33	35.24	38.46	37.72	35.94	32.23	31.69	31.18	33.33	37.31	36.49	
6	LLH rate (per MWh)	B)	27.01	29.58	31.13	32.24	31.73	30.08	26.95	22.29	23.29	28.66	31.4	32.26	
7	Demand rate (kw/Mo)	C)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
9	HLH consumption (MWh)	D)	141,440	136,000	141,440	136,000	130,560	146,880	141,440	136,000	141,440	136,000	146,880	136,000	1,670,080
10	LLH consumption (MWh)	E)	111,520	109,140	111,520	116,960	97,920	105,740	103,360	116,960	103,360	116,960	106,080	108,800	1,308,320
11	Demand (kW)	F)	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	4,080,000
13	HLH revenues (A * D)	G)	4,514,765	4,532,880	4,984,346	5,230,560	4,924,723	5,278,867	4,558,611	4,309,840	4,410,099	4,532,880	5,480,093	4,962,640	57,720,304
14	LLH revenues (B * E)	H)	3,012,155	3,228,361	3,471,618	3,770,790	3,107,002	3,180,659	2,785,552	2,607,038	2,407,254	3,352,074	3,330,912	3,509,888	37,763,304
15	Demand revenues (C * F)	I)	697,000	744,600	782,000	666,400	676,600	629,000	591,600	489,600	448,800	547,400	642,600	666,400	7,582,000
16	TOTAL forecast revenues (G + H + I)	J)	$ 8,223,920	$ 8,505,841	$ 9,237,963	$ 9,667,750	$ 8,708,325	$ 9,088,526	$ 7,935,763	$ 7,406,478	$ 7,266,154	$ 8,432,354	$ 9,453,605	$ 9,138,928	$ 103,065,608
17	TOTAL revenues adjusting for actuals	K)	**$ 8,218,404**	**$ 8,516,137**	**$ 9,238,547**	**$ 9,682,003**	**$ 8,712,506**	**$ 9,077,099**	$ 7,935,763	$ 7,406,478	$ 7,266,154	$ 8,432,354	$ 9,453,605	$ 9,138,928	**$ 103,077,978**
20	**FY 2012 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
21	HLH rate (per MWh)	A)	31.91	33.33	35.24	38.45	37.72	35.94	32.22	31.69	31.18	33.33	37.31	36.49	
22	LLH rate (per MWh)	B)	27.01	29.58	31.13	32.24	31.73	30.07	26.95	22.29	23.29	28.66	31.39	32.26	
23	Demand rate (kw/Mo)	C)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
25	HLH consumption (MWh)	D)	141,440	136,000	141,440	136,000	136,000	146,880	136,000	141,440	141,440	136,000	146,880	130,560	1,670,080
26	LLH consumption (MWh)	E)	111,520	109,140	111,520	116,960	100,640	105,740	108,800	111,520	103,360	116,960	106,080	114,240	1,316,480
27	Demand (kW)	F)	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	4,080,000
29	HLH revenues (A * D)	G)	4,513,350	4,532,880	4,984,346	5,229,200	5,129,920	5,278,867	4,381,920	4,482,234	4,410,099	4,532,880	5,480,093	4,764,134	57,719,923
30	LLH revenues (B * E)	H)	3,012,155	3,228,361	3,471,618	3,770,790	3,193,307	3,179,602	2,932,160	2,485,781	2,407,254	3,352,074	3,329,851	3,685,382	38,048,336
31	Demand revenues (C * F)	I)	697,000	744,600	782,000	666,400	676,600	629,000	591,600	489,600	448,800	547,400	642,600	666,400	7,582,000
32	TOTAL revenues (G + H + I)		$ 8,222,506	$ 8,505,841	$ 9,237,963	$ 9,666,390	$ 8,999,827	$ 9,087,469	$ 7,905,680	$ 7,457,614	$ 7,266,154	$ 8,432,354	$ 9,452,544	$ 9,115,917	$ 103,350,259
34	**FY 2013 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
35	HLH rate (per MWh)	A)	31.91	33.33	35.24	38.45	37.72	35.94	32.22	31.69	31.18	33.33	37.31	36.49	
36	LLH rate (per MWh)	B)	27.01	29.58	31.13	32.24	31.73	30.07	26.95	22.29	23.29	28.66	31.39	32.26	
37	Demand rate (kw/Mo)	C)	2.05	2.19	2.3	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96	
39	HLH consumption (MWh)	D)	146,880	136,000	136,000	141,440	130,560	141,440	141,440	141,440	136,000	141,440	146,880	130,560	
40	LLH consumption (MWh)	E)	106,080	109,140	116,960	111,520	97,920	111,180	103,360	111,520	108,800	111,520	106,080	114,240	
41	Demand (kW)	F)	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	340,000	
43	HLH revenues (A * D)	G)	4,686,941	4,532,880	4,792,640	5,438,368	4,924,723	5,083,354	4,557,197	4,482,234	4,240,480	4,714,195	5,480,093	4,764,134	57,697,238
44	LLH revenues (B * E)	H)	2,865,221	3,228,361	3,640,965	3,595,405	3,107,002	3,343,183	2,785,552	2,485,781	2,533,952	3,196,163	3,329,851	3,685,382	37,796,817
45	Demand revenues (C * F)	I)	697,000	744,600	782,000	666,400	676,600	629,000	591,600	489,600	448,800	547,400	642,600	666,400	7,582,000
46	TOTAL revenues (G + H + I)		$ 8,249,162	$ 8,505,841	$ 9,215,605	$ 9,700,173	$ 8,708,325	$ 9,055,536	$ 7,934,349	$ 7,457,614	$ 7,223,232	$ 8,457,758	$ 9,452,544	$ 9,115,917	$ 103,076,056
48	**FY 2012 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
49	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	
50	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	
51	Demand rate (kw/Mo)	C)	9.35	9.46	10.13	9.74	9.75	9.36	8.57	8.15	8.39	10.55	10.99	10.38	
53	HLH consumption (MWh)	D)	141,648	136,200	141,648	136,200	136,200	147,096	136,200	141,648	141,648	136,200	147,096	130,752	1,670,080
54	LLH consumption (MWh)	E)	111,684	109,301	111,684	117,132	100,788	105,896	108,960	111,684	103,512	117,132	106,236	114,408	1,316,480
57	HLH revenues (A * D)	G)	5,454,864	5,314,524	5,913,804	5,540,616	5,663,196	5,916,201	5,200,116	5,058,250	5,187,150	5,818,464	6,619,320	5,766,163	67,452,669
58	LLH revenues (B * E)	H)	3,557,135	3,503,081	3,801,723	3,789,220	3,408,650	3,492,434	3,384,298	2,797,684	2,450,129	3,579,554	3,484,541	3,917,330	41,165,779
59	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	TOTAL revenues (G + H + I)		$ 9,012,000	$ 8,817,605	$ 9,715,527	$ 9,329,836	$ 9,071,846	$ 9,408,635	$ 8,584,414	$ 7,855,934	$ 7,637,279	$ 9,398,018	$ 10,103,861	$ 9,683,493	$ 108,618,448
62	**FY 2013 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
63	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	
64	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	
65	Demand rate (kw/Mo)	C)	9.35	9.46	10.13	9.74	9.75	9.36	8.57	8.15	8.39	10.55	10.99	10.38	
67	HLH consumption (MWh)	D)	147,096	136,200	136,200	141,648	130,752	141,648	141,648	141,648	136,200	141,648	147,096	130,752	1,670,080
68	LLH consumption (MWh)	E)	106,236	109,301	117,132	111,684	98,064	111,344	103,512	111,684	108,960	111,684	106,236	114,408	1,308,320
71	HLH revenues (A * D)	G)	5,664,667	5,314,524	5,686,350	5,762,241	5,436,668	5,697,083	5,408,121	5,058,250	4,987,644	6,051,203	6,619,320	5,766,163	67,452,233
72	LLH revenues (B * E)	H)	3,383,617	3,503,081	3,987,173	3,612,977	3,316,524	3,672,109	3,215,083	2,797,684	2,579,083	3,413,063	3,484,541	3,917,330	40,882,265
73	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
74	TOTAL revenues (G + H + I)		$ 9,048,284	$ 8,817,605	$ 9,673,523	$ 9,375,218	$ 8,753,193	$ 9,369,191	$ 8,623,203	$ 7,855,934	$ 7,566,727	$ 9,464,266	$ 10,103,861	$ 9,683,493	$ 108,334,498
76	*Ties to Table 4.1, Revenue at Current Rates, and 4.2, Revenue at Proposed Rates, line 20*														

Table 4.11 - Forecasted Revenues from GTA Delivery Charge

	A	B		C	
1	**Forecasted Revenue from GTA Delivery Charge**				
2					
3					
4		**FY2012**		**FY2013**	
5	**October**	$	180,810	$	183,952
6	**November**	$	242,342	$	246,048
7	**December**	$	250,173	$	253,795
8	**January**	$	270,145	$	273,528
9	**February**	$	228,692	$	228,621
10	**March**	$	230,416	$	233,658
11	**April**	$	178,710	$	181,075
12	**May**	$	159,726	$	162,057
13	**June**	$	239,948	$	243,585
14	**July**	$	220,422	$	223,496
15	**August**	$	199,025	$	201,890
16	**September**	$	223,386	$	226,769
17					
18	**Total**	**$**	**2,623,794**	**$**	**2,658,473**
19					

SECTION 5: AVERAGE SYSTEM COSTS

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Table Descriptions

Table 5.1
Forecast Gross Exchange Costs
Table lists the monthly Forecasted Gross Exchange Costs for each utility.

Table 5.2
REP Residential Exchange Loads
Table lists the monthly Residential Exchange Loads as submitted in each utility's ASC filing.

Table 5.3
Forecast ASCs
Table lists the monthly Forecasted ASCs as determined through the ASC review process.

Table 5.4
Weighted Average ASCs
Table lists the annual Weighted Average ASC fore each utility.

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Table 5.1

Forecast Gross Exchange Costs[1] ($)

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	FY 2012
Avista	14,354,094	16,914,465	23,285,608	27,709,223	23,663,638	21,482,637	19,111,509	16,372,073	14,784,300	14,346,780	16,887,824	15,499,678	224,411,828
Idaho Power	19,241,203	17,483,522	24,603,402	29,062,364	24,750,401	22,441,789	20,196,036	17,860,365	19,105,307	20,315,132	25,419,213	22,745,983	263,224,718
Northwestern	2,493,694	2,934,297	3,639,311	3,816,483	3,456,366	3,074,726	2,883,898	2,618,311	2,530,710	2,613,769	2,778,602	2,599,022	35,439,189
PacifiCorp	37,524,085	41,757,100	59,805,691	65,414,778	52,188,564	47,696,625	43,344,032	40,086,390	40,579,899	47,589,228	51,328,936	42,517,928	569,833,255
PGE	40,449,685	46,143,277	62,743,584	70,378,369	58,669,565	55,083,387	49,377,820	42,876,512	41,761,985	42,375,506	47,852,713	43,291,649	601,004,053
Puget Sound Energy	52,435,718	65,393,204	87,138,527	95,637,216	82,865,225	77,595,912	69,665,001	60,151,780	53,266,552	49,925,889	50,345,894	51,334,885	795,755,803
Clark	9,225,909	12,388,961	14,585,000	18,614,616	16,902,456	16,132,630	14,623,101	14,552,094	9,419,634	9,609,399	9,146,180	10,412,007	155,611,988
Snohomish	12,119,939	11,878,689	16,202,971	23,612,384	17,939,828	17,460,446	15,996,811	14,016,363	11,199,873	10,309,098	10,591,386	8,387,720	169,715,508

	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	FY 2013
Avista	14,354,094	16,914,465	23,285,608	27,709,223	23,663,638	21,482,637	19,111,509	16,372,073	14,784,300	14,346,780	16,887,824	15,499,678	224,411,828
Idaho Power	19,241,203	17,483,522	24,603,402	29,062,364	24,750,401	22,441,789	20,196,036	17,860,365	19,105,307	20,315,132	25,419,213	22,745,983	263,224,718
Northwestern	2,493,694	2,934,297	3,639,311	3,816,483	3,456,366	3,074,726	2,883,898	2,618,311	2,530,710	2,613,769	2,778,602	2,599,022	35,439,189
PacifiCorp	37,524,085	41,757,100	59,805,691	65,414,778	52,188,564	47,696,625	43,344,032	40,086,390	40,579,899	47,589,228	51,328,936	42,517,928	569,833,255
PGE	40,449,685	46,143,277	62,743,584	70,378,369	58,669,565	55,083,387	49,377,820	42,876,512	41,761,985	42,375,506	47,852,713	43,291,649	601,004,053
Puget Sound Energy	52,435,718	65,393,204	87,138,527	95,637,216	82,865,225	77,595,912	69,665,001	60,151,780	53,266,552	49,925,889	50,345,894	51,334,885	795,755,803
Clark	9,322,338	12,518,358	14,737,282	18,809,083	17,078,738	16,300,871	14,775,508	14,703,634	9,517,547	9,709,169	9,241,001	10,520,003	157,233,533
Snohomish	12,231,841	11,988,348	16,352,546	23,838,330	18,111,482	17,627,470	16,149,847	14,150,489	11,306,998	10,407,694	10,692,711	8,467,991	171,325,746

[1]The Forecast Gross Exchange Cost is calculated by multiplying each utility's Forecasted Residential Exchange Load by the utility's Forecast ASC.

Table 5.2

REP Residential Exchange Loads[2] (MWh)

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	FY 2012
Avista	249,810	294,369	405,249	482,235	411,828	373,871	332,605	284,930	257,297	249,683	293,906	269,747	3,905,531
Idaho Power	411,753	374,139	526,501	621,921	529,647	480,244	432,186	382,203	408,845	434,734	543,959	486,753	5,632,885
Northwestern	45,053	53,014	65,751	68,952	62,446	55,551	52,103	47,305	45,722	47,223	50,201	46,956	640,274
PacifiCorp	623,531	693,870	993,780	1,086,985	867,208	792,566	720,240	666,108	674,309	790,781	852,923	706,513	9,468,814
PGE	590,679	673,821	916,232	1,027,722	856,740	804,372	721,055	626,117	609,842	618,801	698,784	632,179	8,776,344
Puget Sound Energy	793,639	989,756	1,318,882	1,447,513	1,254,204	1,174,450	1,054,412	910,425	806,214	755,651	762,008	776,977	12,044,132
Clark	155,214	208,428	245,373	313,166	284,362	271,410	246,014	244,820	158,473	161,666	153,872	175,168	2,617,967
Snohomish	259,694	254,525	347,182	505,944	384,397	374,126	342,764	300,329	239,980	220,893	226,942	179,724	3,636,501

	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	FY 2013
Avista	249,810	294,369	405,249	482,235	411,828	373,871	332,605	284,930	257,297	249,683	293,906	269,747	3,905,531
Idaho Power	411,753	374,139	526,501	621,921	529,647	480,244	432,186	382,203	408,845	434,734	543,959	486,753	5,632,885
Northwestern	45,053	53,014	65,751	68,952	62,446	55,551	52,103	47,305	45,722	47,223	50,201	46,956	640,274
PacifiCorp	623,531	693,870	993,780	1,086,985	867,208	792,566	720,240	666,108	674,309	790,781	852,923	706,513	9,468,814
PGE	590,679	673,821	916,232	1,027,722	856,740	804,372	721,055	626,117	609,842	618,801	698,784	632,179	8,776,344
Puget Sound Energy	793,639	989,756	1,318,882	1,447,513	1,254,204	1,174,450	1,054,412	910,425	806,214	755,651	762,008	776,977	12,044,132
Clark	156,836	210,605	247,935	316,438	287,327	274,241	248,579	247,369	160,120	163,344	155,468	176,985	2,645,248
Snohomish	262,092	256,875	350,387	510,785	388,075	377,705	346,043	303,203	242,276	223,006	229,113	181,444	3,671,004

[2]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 5.3

Forecast ASCs[3] ($/MWh)

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	FY 2012
Avista	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46
Idaho Power	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73
Northwestern	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35
PacifiCorp	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18
PGE	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48
Puget Sound Energy	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07
Clark	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44
Snohomish	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67

	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	FY 2013
Avista	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46	57.46
Idaho Power	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73	46.73
Northwestern	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35	55.35
PacifiCorp	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18	60.18
PGE	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48	68.48
Puget Sound Energy	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07	66.07
Clark	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44	59.44
Snohomish	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67	46.67

[3]Forecasted ASCs are determined through the ASC review process.

Table 5.4

Weighted Average ASCs[4] ($/MWh)

	FY 2012
Avista	57.46
Idaho Power	46.73
Northwestern	55.35
PacifiCorp	60.18
PGE	68.48
Puget Sound Energy	66.07
Clark	59.44
Snohomish	46.67

	FY 2013
Avista	57.46
Idaho Power	46.73
Northwestern	55.35
PacifiCorp	60.18
PGE	68.48
Puget Sound Energy	66.07
Clark	59.44
Snohomish	46.67

[4]Weighted Average ASCs are calculated by dividing each utility's annual Forecast Gross Exchange Cost by the annual REP Residential Exchange Load

Bonneville Power Administration
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