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2010 BPA Rate Case
Wholesale Power Rate Initial Proposal

WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION
Volume 1

February 2009

WP-10-E-BPA-05A

BONNEVILLE
POWER ADMINISTRATION

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet
kcfs	thousand (kilo) cubic feet per second

K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVAr	megavolt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
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)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (formerly National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission

NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
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
PS	BPA Power Services
PSC	power sales contract
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
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert

TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
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
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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DOCUMENTATION FOR THE WHOLESALE POWER RATE DEVELOPMENT STUDY

INTRODUCTION

The Documentation for Wholesale Power Rate Development Study (WPRDS) shows the details of the calculation of the proposed 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 (RAM2010). The RAM2010 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. The output tables of RAM2010 include billing determinants, which are based on power sales forecasts, and revenue requirements used in the WPRDS cost of service analysis (COSA). Other tables show the initial allocation of the revenue requirement over the billing determinants. Next, tables present the rate design steps, the basis for which is sections 7(b) and 7(c) of the Northwest Power Act. Other major tables show calculation of the Slice rate and the non-Slice rates. The final table shows the calculation of the resource cost contributions that appear in GRSP section II.C.

Section 3 documents forecasts of the Slice True-Up Adjustment Charge, both before and after the cost shift described in WPRDS section 2.15.6.

Section 4 documents revenue forecasts at both current and proposed rates for the rate period, FY 2010-2011, and at current rates for the period immediately preceding the two-year rate period, FY 2009.

Appendices document the section 7(c)(2) Industrial Margin Study (Appendix A) and provide further information on BPA's policy for the development of regional conservation and renewable resources (Appendices B, C, and D).

1. RATE PROCESS MODELING

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

LOADS AND RESOURCES STUDY (WP-10-E-BPA-01):

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 Loads and Resources Study (WP-10-E-BPA-01).

Hydro Regulation Study (HYDSIM)
The Federal system regulated hydro resource estimates are derived by BPA's hydro regulation model (HYDSIM), which estimates project generation under 70 water years (October 1928 through September 1998). BPA uses HYDSIM to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the PNW Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for the 70 water years of record. The hydro regulation study uses plant operating characteristics and conditions to determine energy production expected from each specific project. Physical characteristics of each project are provided by annual Pacific Northwest Coordination Agreement (PNCA) data submittals from regional utilities and government agencies involved in the coordination and operation of regional hydro projects. The HYDSIM model incorporates these operating characteristics along with power and non-power requirements to provide project-by-project monthly energy generation estimates for the Federal system regulated hydro projects for FY 2010-2011. The HYDSIM studies incorporate the power and non-power operating requirements BPA expects to be in effect during the rate period, including those described by the NOAA Fisheries in its Biological Opinion (BiOp), published May 5, 2008; the United States Fish and Wildlife Service (USFWS) BiOp, published December 2000; operations described in the Northwest Power and Conservation Council's Fish and Wildlife Program; and other fish mitigation measures.

Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow augmentation, minimum flow levels, spill for juvenile fish passage, reservoir drawdown limitations, and turbine operation efficiency requirements. HYDSIM uses hydro plant operating characteristics in combination with the power and non-power requirements to simulate the coordinated operation of the hydro system. For the WP-10 Initial Proposal, the Federal hydro plant operating characteristics were updated to include increased reserve requirements associated with new wind generating plants. These reserve requirements are incorporated into the availability factors in HYDSIM and reduce the powerhouse capacity available for generation. The Federal system hydro generation is used in the Federal system loads and resources balance and is detailed in the Loads and Resources Study (WP-10-E-BPA-01).

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 Loads and Resources Study (WP-10-E-BPA-01). Loads and Resources Study results are used as input into the Risk Analysis and Mitigation Study (WP-10-E-BPA-04) and the Market Price Forecast Study (WP-10-E-BPA-03).

REVENUE REQUIREMENT STUDY (WP-10-E-BPA-02):

The Revenue Requirement Study provides BPA's generation revenue requirement for the rate test period. The revenue requirement is assigned to the resource pools for use in the Cost of Service Analysis section of the WPRDS.

The Revenue Requirement Study 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. The Repayment Program is used to determine whether a given set of annual revenues is sufficient to meet a given set of annual expenses and cover a given set of long-term obligations when applied in accordance with the requirements of DOE Order RA 6120.2. The Repayment Program also is used to determine by what minimum factor the future revenues can be multiplied to obtain a new set of revenues that will be sufficient.

MARKET PRICE FORECAST STUDY (WP-10-E-BPA-03):

The electric energy price results from the Market Price Forecast Study are used as price inputs for the following: (a) the secondary revenue forecast, (b) augmentation purchase costs, (c) the risk analysis, (d) the variable cost for generation input capacity, (e) utility average system costs, and (f) rate design. The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA$^{xmp®}$. AURORA$^{xmp®}$ is an economic fundamentals-based software application that models wholesale electric energy transactions in a competitive pricing system. AURORA$^{xmp®}$ 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$^{xmp®}$ 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. Over time, AURORA$^{xmp®}$ will add new resources and retire old resources based on the net present value of the resource.

RISK ANALYSIS AND MITIGATION STUDY (WP-10-E-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; a set of computer programs that manage data, referred to as Data Management Procedures; 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 forecasted 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 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 AURORA$^{xmp®}$ prices under 1937 hydro conditions. The Rate Analysis Model and the Revenue Forecast Model 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$^{xmp®}$ 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 Loads and Resources Study (WP-10-E-BPA-01).

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 the probability of making all planned Treasury payments during the rate period given the risks quantified in RiskMod and NORM and accounting for the impact of the risk mitigation tools. The ToolKit is used to demonstrate BPA's ability to meet its Treasury Payment Probability (TPP) standard for the rate proposal, given the net revenue and cash variability embodied in the distributions of operating and non-operating risks. 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.

WHOLESALE POWER RATE DEVELOPMENT STUDY (WP-10-E-BPA-05):

Rate Analysis Model (RAM2010)
RAM2010, a spreadsheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis (COSA), Rate Design, and Slice Separation.

1. Cost of Service Analysis. 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 Design. The Northwest Power Act requires that some rate adjustments be made after the initial allocation of costs to ensure that the rate levels for the individual rate pools (PF Preference, PF Exchange, IP, NR, and FPS) have the proper relationship to each other. The primary rate adjustments are described in sections 7(b) and 7(c) of the Northwest Power Act. The Rate Design step of RAM2010 performs these rate adjustments, including the 7(b)(2) rate test. Net exchange costs from this step are provided to the Lookback Recovery and Return Study (WP-10-E-BPA-09) for

calculation of the amount of exchange costs to be credited back to the COUs and the amount of exchange benefits to be distributed to the IOUs.

3. Slice Separation and Other Rate Design Application. In the Rate Design step, costs are allocated to the various rate pools, including the PF Preference rate pool that contains all firm PF Preference load. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. At the end of the rate design step, BPA applies various designs to the different rates. The Slice Separation step separates the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool. What remains is the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges.

Revenue and Purchased Power Expense Forecast

The Revenue Forecast, section 4 of the WPRDS, presents BPA's expected level of sales and revenue for the rate period, FY 2010 and FY 2011. It documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR) to projected billing determinants. These two revenue forecasts, one with current rates and the other with proposed rates, are used to demonstrate that current rates will not recover BPA's revenue requirement and that proposed rates will recover the revenue requirement. The revenue test is described in the Revenue Requirement Study, WP-10-E-BPA-02. 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 2010-2011 Average System Cost (ASC) Forecasts

The 7(b)(2) rate test requires a forecast of utility ASCs for the period FY 2010-2015. For purposes of the Initial Proposal, for the rate period BPA proposes to use the ASCs filed by utilities on October 15, 2008, with certain modifications, as "placeholders" pending the completion of the ASC Review Process. These "placeholder" ASCs will be replaced with the final ASCs established in the ASC Reports BPA publishes at the end of the current ASC Review Process. At the close of the ASC Review Process, BPA will incorporate into the WP-10 rate case record the final ASC Reports, and the Final Proposal rates will be established using these final ASCs for FY 2010-2011. The methodology and data that BPA uses to forecast utility ASCs for the rest of the 7(b)(2) rate test period, FY 2012-2015, is included in the Section 7(b)(2) Rate Test Study (WP-10-E-BPA-06) and the Loads and Resources Study (WP-10-E-BPA-01).

SECTION 7(b)(2) RATE TEST STUDY (WP-10-BPA-E-06):

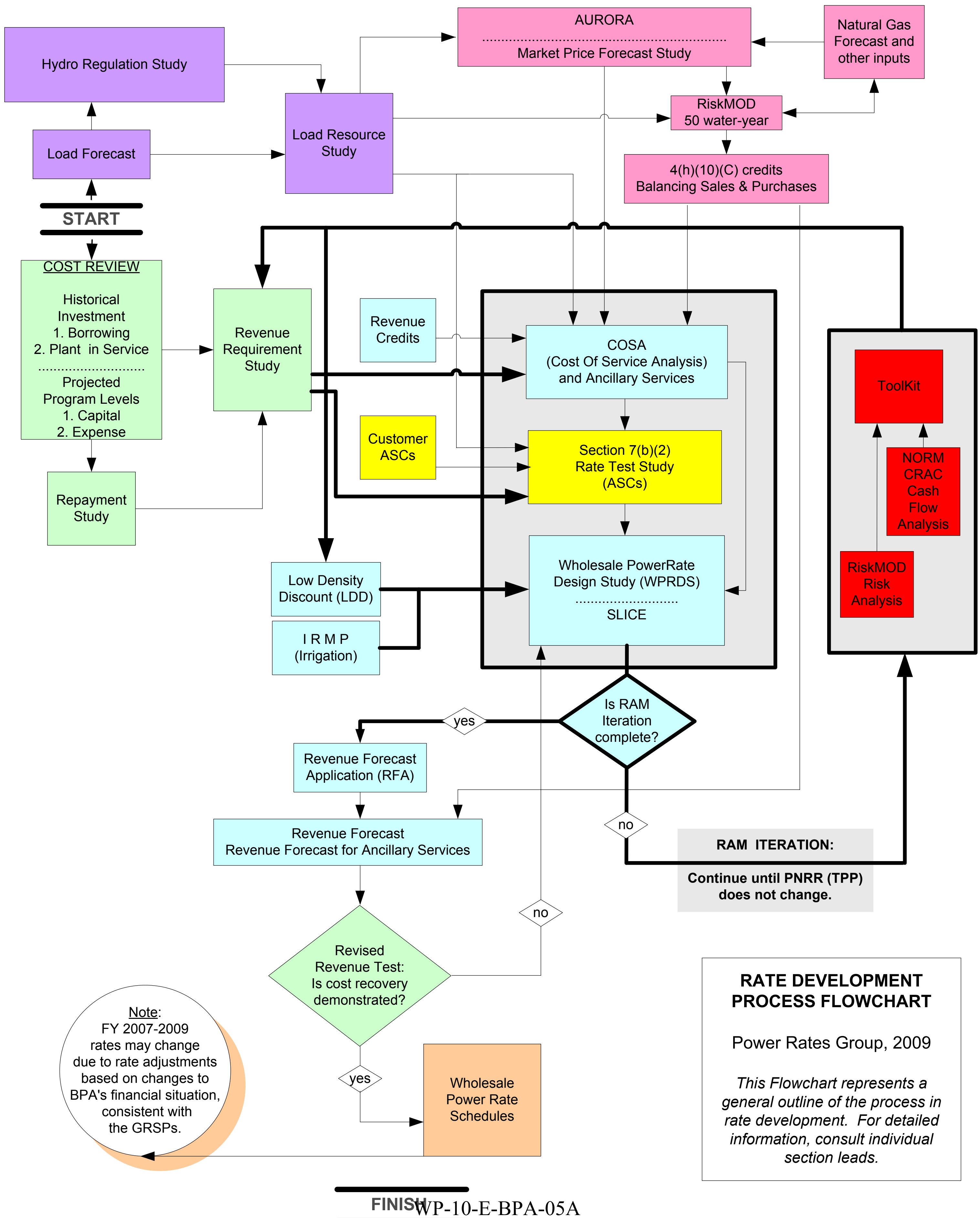
The Rate Design steps of RAM2010 calculate the Program Case for the 7(b)(2) rate test. RAM2010 calculates annual Program Case rates for the rate period and the following four years, pursuant to section 7(b)(2) of the Northwest Power Act and BPA's Legal Interpretation and Implementation Methodology. The method of calculating rates and the data used to calculate rates for the Program Case of the 7(b)(2) rate test are identical to those used in calculating the actual proposed rates. The sales forecast used to develop rates for the Program Case is the same forecast used to develop BPA's proposed rates. The 7(b)(2) Case section of RAM2010 calculates 7(b)(2) Case rates the same way as Program Case rates, except where section 7(b)(2) of the Northwest Power Act requires specific assumptions be made that modify the Program Case.

GENERATION INPUTS STUDY (WP-10-E-BPA-08):

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 next other is the "deployment costs," those costs incurred when the system uses its reserve capability to actually deliver in response to a reserve need. The GARD model produces the following costs associated with standing ready: 1) energy shift, 2) efficiency loss, and 3) base cycling loss. GARD also calculates the following costs associated with deploying reserves: 1) response losses, 2) incremental cycling losses, 3) incremental spill, and 4) incremental efficiency loss. 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.

RATE DEVELOPMENT PROCESS FLOWCHART



CHAPTER 2: RATE ANALYSIS MODEL

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Description of Ratemaking Tables

Table 2.1 (Sales_01)
Total PF Load Forecast FY2010-11 and Non-Slice PF Load Forecast, FY2010-11.
Gigawatthour (GWh) energy sales and peak kilowatt (kW)/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

Table 2.2 (Sales_02)
Total PF Exchange Load Forecast, FY2010-11.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

Table 2.2 (Sales_03)
Total IP Load Forecast, FY2010-11.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

Table 2.2 (Sales_04)
Total NR Load Forecast, FY2010-11.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2010-11. (Note: No sale under the NR rate schedule is forecast for this test period. In order to calculate a rate in the case where there is no actual load, the token load of 0.0001 aMW was used.)

Table 2.3.1 (COSA_06 FY2010)
Itemized Revenue Requirement, FY2010.
Power Business Line (PBL) revenue requirements for the fiscal year 2010 rate test period.

Table 2.3.2 (COSA_06 FY2011)
Itemized Revenue Requirement, FY2011.
Power Business Line (PBL) revenue requirements for the fiscal year 2011 rate test period

Table 2.3.3 (COSA_07)
Functionalization of Residential Exchange Costs, FY2010-11.
REP costs are functionalized to power to comport with other functionalized costs moving through the COSA into the Rate Design Step of the RAM.

Description of Ratemaking Tables

Table 2.3.4 (COSA_08)
Classified Revenue Requirement, FY2010-11.
Generation costs are classified between energy, demand, and load variance. All costs move through the COSA into the Rate Design Step of the RAM. Demand charge and load variance charge revenues are applied to the generation revenue requirement during the calculation of energy charges.

Table 2.3.5 (COSA_09)
Functionalized Revenue Credits, FY2010-11.
Revenue credits are anticipated revenues during the rate test period. In tables that follow, these revenue credits are directly assigned to Federal Base System (FBS) power and have the effect of reducing the cost of FBS resources in the ratemaking process.

Table 2.3.6 (COSA_09A)
Allocation of EE Revenue Credits to Conservation Costs, FY2010-11.
Energy Efficiency revenues are credited against conservation program costs rather than being directly assigned to Federal Base System (FBS) power as are the bulk of BPA's other revenue credits.

Table 2.4.1 (ALLOCATE 01)
Energy Allocation Factors with Residential Exchange Included, FY2010-11.
Values are derived from the rate case load/resource balance and are average megawatt (aMW) at generation level (sales plus transmission losses). These EAFs are used in the resource pool to rate pool allocation determination.

Table 2.4.2 (ALLOCATE 02)
Initial Rate Pool Cost Allocation, FY2010-11.
Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

Table 2.5.1 (RDS_05)
Average Cost of Nonfirm Energy, FY2010-11.
Table calculates BPA's Average Cost of Nonfirm Energy.

Table 2.5.2 (RDS_06)
Bonneville Average System Cost, FY2010-11.
Table calculates BPA's Average System Cost (BASC).

Description of Ratemaking Tables

Table 2.5.3 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2010-11.
Tables summarize revenue from secondary power sales and revenues from Other Revenue Credits from Table COSA 09. These revenues are then allocated to rate pools using the EAFs from table ALLOCATE 01. The allocation is based on the service provided by the FBS and NR resources to these rate pools.

Table 2.5.4 (RDS_17)
Calculation of FPS (Surplus)/Shortfall, FY2010-11.
Table calculates the firm surplus sale revenue (surplus)/shortfall. Generation revenue requirement costs allocated to FPS sales in table ALLOCATE 02 are reduced by the excess revenue credit allocated to FPS sales in table RDS_11. 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 2.5.5 (RDS_19)
Summary of Initial Cost Allocations, FY2010-11.
Table summarizes the allocations from Tables ALLOCATE 02, RDS 11, and RDS 17, as well as allocates Low Density Discount and Irrigation Rate Mitigation costs to the PF Preference rate pool.

Table 2.5.6 (RDS_21)
7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta, FY2010-11.
Table solves a formula for calculating the 7(c)(2) delta appropriate for this point in the model. Table allocates the 7(c)(2) delta to PF and NR rate classes based on allocation factors developed in ALLOCATE 01.

Table 2.5.7 (RDS_23)
Industrial Firm Power Floor Rate Calculation, FY2010-11.
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.

Description of Ratemaking Tables

Table 2.5.8 (RDS_24)
Industrial Firm Power Floor Rate Test, FY2010-11.
Table performs the DSI floor rate test and calculates the DSI floor rate adjustment if applicable. IP revenue under proposed rates is compared with revenue under the DSI floor rate. If DSI floor rate revenues are greater, a DSI floor rate adjustment is required. The amount of the DSI floor rate adjustment is then added to the IP allocated costs and subtracted from the other firm power rate pools allocated costs.

Table 2.5.9 (RDS_30)
Calculation of 7(b)(2) Protection Amount, FY2010-11.
Table calculates the 7(b)(2) PF preference protection amount, based on the "7(b)(2) trigger" calculated in the 7(b)(2) rate test. The protection amount is the 7(b)(2) trigger in mills/kWh times the PF preference billing determinants.

Table 2.5.9A (RDS_31)
Allocation of 7(b)(2) Protection Amount, FY2010-11.
Table allocates the 7(b)(2) protection amount from RDS_30 to PF Exchange, IP and NR rate pools. Allocation is based on allocation factors developed in ALLOCATE 01.

Table 2.5.10 (RDS_33)
7(b)(2) Industrial Adjustment 7(c)(2) Delta Calculation, FY2010-11.
Table calculates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is the difference between the DSI allocated revenue requirement at this point in the modeling and the expected DSI revenues. Expected DSI revenues are; IP revenues at the PF preference rate; plus revenues at the net industrial margin; plus 7(b)(2) protection amount allocated to the IP class.

Table 2.6.1 (SLICESEP_01)
Slice PF Product Separation, FY2010-11.
The previous rate design steps have been accomplished using the total firm PF Preference load in the PF Preference load pool. This table recognizes the PF Slice product by removing the firm loads, allocated costs, and secondary revenue credit associated with the PF Slice product from the PF Preference load pool. Here after, the PF Preference rate will be for the non-Slice portion of the PF firm loads.

Description of Ratemaking Tables

Table 2.6.2 (SLICESEP_02)
After Slice Separation Step 7(c)(2) Delta Calculation, FY2010-11.
Table calculates the After Slice Separation Step Adjustment_7(c)(2) Delta. The Slice Separation Step produces a non-Slice PF Preference rate. The After Slice Separation Step Adjustment links the IP rate to this new non-Slice PF Preference rate

Table 2.7 (PF 2010)
Calculation of Priority Firm Preference Rate Components, FY2010-11.
Table calculates Priority Firm Preference rates. Marginal cost rates are scaled to produce rates that recover costs allocated to PF Preference energy. The demand charges are identical for all rate pools.

Table 2.8 (Unbifurcated PF 2010)
Calculation of Unbifurcated Priority Firm Rate Components, FY2010-11.
Table calculates the Unbifurcated Priority Firm rates. Marginal cost rates are scaled to produce rates that recover costs allocated to the Unbifurcated PF energy. The demand charges are identical for all rate pools. A delivery change is added and the delivered Unbifurcated PF is used as the base for the utility specific PF Exchange rates.

Table 2.9 (REP_1)
Calculation of Utility Specific Priority Firm Exchange Rates and Net REP Benefits, FY2010-11.
All utilities with ASCs above the delivered unbifurcated Priority Firm rate will receive REP benefits. The table determines which potential exchanging utilities will be expected to participate in the REP and then calculates individual Supplemental 7(b)(3) Charges that, in total, will collect the total 7(b)(3) costs allocated to the PF Exchange rate pool. A utility's specific PF Exchange rate is the delivered unbifurcated PF rate plus their individual Supplemental 7(b)(3) Charge. The PF Exchange rates are then used to determine each exchanging utilities' REP benefits.

Table 2.9A (Average PFx 2010)
Calculation of Average Priority Firm Exchange Rate Components, FY2010-11.
Table calculates the Average Priority Firm Exchange rate to demonstrate that costs allocated to the PF Exchange rate pool are recovered. Marginal cost rates are scaled to produce rates that recover costs allocated to PF Exchange energy. The demand charges are identical for all rate pools. While the utility specific PF Exchange rates in Table 2.9 above are used to determine REP benefits for each exchanging utility, their load-weighted average equals (with rounding) the Average PF Exchange rate calculated in this table.

Description of Ratemaking Tables

Table 2.10 (IP 2010)
Calculation of Industrial Firm Power Rate Components, FY2010-11.
Table calculates Industrial Firm Power rates. Marginal cost rates are scaled to produce rates that recover costs allocated to IP energy. The demand charges are identical for all rate pools.

Table 2.11 (NR 2010)
Calculation of New Resource Rate Components, FY2010-11.
Table calculates New Resource rates. Marginal cost rates are scaled to produce rates that recover costs allocated to NR energy. The demand charges are identical for all rate pools.

Table 2.12 (PF 2010 Flat)
Flat Priority Firm Rate Calculation, FY2010-11.
Table calculates the average annual flat Priority Firm Preference rate. The PF Preference energy and demand rates are applied to a flat load to determine an average annual flat PF Preference rate.

Table 2.13 (Slice Costing Table)
Slice Product Pricing, FY2010-11.
Table shows the costs and revenue credits associated with the PF Slice Product and calculates a cost per month per Slice Product percent.

Description of Ratemaking Tables

Table 2.14.1 (RDS_60A)
Allocated Costs and Unit Costs, Priority Firm Power, FY2010-11.
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Power. A percent contribution to the final Priority Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.14.2 (RDS_60B)
Allocated Costs and Unit Costs, Priority Firm Preference Power and Priority Firm Exchange Power, FY2010-11.
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Preference 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 2.14.3 (RDS_61)
Allocated Costs and Unit Costs, Industrial Firm Power, FY2010-11.
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 2.14.4 (RDS_62)
Allocated Costs and Unit Costs, New Resource Firm Power, FY2010-11.
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 2.14.5 (RDS_63)
Resource Cost Contribution, FY2010-11.
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, FPS.

Table 2.1

Sales 01

Total PF Load Forecast FY2010-11
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2010	HLH	3,011	3,289	3,654	3,623	3,259	3,237	2,863	3,071	2,970	3,063	3,153	2,857	63,643	7,265
	LLH	1,892	2,382	2,516	2,604	2,130	2,052	1,838	2,210	1,864	2,134	2,023	1,949		
	Demand	8,264	9,181	9,547	10,030	9,591	8,470	7,678	7,684	7,176	8,018	7,727	7,477		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	2,986	3,400	3,697	3,666	3,302	3,275	2,825	3,007	2,905	3,066	3,249	2,887	63,885	7,293
	LLH	1,972	2,335	2,541	2,630	2,156	2,074	1,811	2,160	1,821	2,177	1,977	1,966		
	Demand	8,367	9,323	9,677	10,158	9,719	8,582	7,593	7,543	7,037	8,067	7,845	7,575		

Non-Slice PF Load Forecast FY2010-11
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2010	HLH	2,304	2,486	2,886	2,864	2,624	2,619	2,313	2,226	2,225	2,338	2,401	2,211	49,330	5,631
	LLH	1,448	1,801	1,987	2,059	1,715	1,660	1,485	1,602	1,397	1,629	1,540	1,508		
	Demand	6,326	6,938	7,540	7,930	7,722	6,853	6,205	5,570	5,377	6,120	5,883	5,788		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	2,289	2,574	2,923	2,902	2,662	2,652	2,344	2,256	2,257	2,355	2,480	2,240	49,963	5,704
	LLH	1,512	1,767	2,009	2,082	1,738	1,679	1,503	1,620	1,415	1,672	1,509	1,525		
	Demand	6,413	7,057	7,652	8,041	7,835	6,949	6,300	5,658	5,465	6,196	5,987	5,877		

Table 2.2

Sales 02

Total PF Exchange Load Forecast FY2010-11

GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2010	HLH	1,785	2,030	2,615	2,889	2,710	2,533	2,288	1,516	1,262	1,227	1,633	2,006	38,924	4,443
	LLH	1,080	1,167	1,470	1,896	1,719	1,530	1,308	950	686	692	816	1,115		
	Demand	5,934	6,279	7,966	9,035	8,729	6,370	6,195	4,249	3,585	4,090	4,833	5,912		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	1795	2038	2622	2887	2710	2534	2323	1552	1307	1274	1678	2044	39,366	4,494
	LLH	1087	1173	1475	1896	1720	1531	1330	974	713	722	842	1138		
	Demand	5959	6301	7982	9027	8728	6373	6289	4344	3708	4235	4961	6017		

Sales 03

Total IP Load Forecast FY2010-11

GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2010	HLH	167	161	161	167	154	174	161	167	167	161	174	154	3522	402
	LLH	132	129	138	132	116	125	129	132	122	138	125	135		
	Demand	402	402	402	402	402	402	402	402	402	402	402	402		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	174	161	161	167	161	167	167	167	161	167	167	161	3531	403
	LLH	125	129	138	132	119	131	122	132	129	132	132	129		
	Demand	402	402	402	402	402	402	402	402	402	402	402	402		

Sales 04

Total NR Load Forecast FY2010-11

GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2010	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		

Table 2.3.1

COSA 06 - FY2010

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2010

($ 000)

		A	B	C	D	E	F
		INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**	
1	1. GENERATION COSTS						
2							
3	2. FEDERAL BASE SYSTEM						
4	3. HYDRO	0	133,499	134,290	433,943	701,732	
5	4. BPA FISH & WILDLIFE PROGRAM	204,098	17,296	17,400	263,845	298,541	
6	5. TROJAN				2,200	2,200	
7	6. WNP #1				163,589	163,589	
8	7. WNP #2				503,533	503,533	
9	8. WNP #3				139,704	139,704	
10	9. SYSTEM AUGMENTATION				176,580	348,990	172,410
11	10. BALANCING POWER PURCHASES				63,288	63,288	
12	**11. TOTAL FEDERAL BASE SYSTEM**	**204,098**	**150,795**	**151,690**	**1,746,681**	**2,221,576**	
13							
14	12. NEW RESOURCES						
15	13. IDAHO FALLS				2,788	2,788	
16	14. COWLITZ FALLS				14,354	14,354	
17	15. OTHER NEW RESOURCES PURCHASES				66,719	66,719	
18	**16. TOTAL NEW RESOURCES**				**83,861**	**83,861**	
19							
20	17. RESIDENTIAL EXCHANGE				2,168,413	2,168,413	
21							
22	18. CONSERVATION		13,754	13,835	170,130	197,719	
23							
24	19. OTHER GENERATION COSTS						
25	20. BPA PROGRAMS	15,032	1,274	1,281	149,044	151,599	
26	21. WNP #3 PLANT				0	0	
27	**22. TOTAL OTHER GENERATION COSTS**	**15,032**	**1,274**	**1,281**	**149,044**	**151,599**	
28							
29	**23. TOTAL GENERATION COSTS**	**219,130**	**165,823**	**166,806**	**4,318,129**	**4,823,168**	
30							
31	24. TRANSMISSION COSTS						
32	25. TBL TRANSMISSION/ANCILLARY SERVICES				121,472	121,472	
33	26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000	
34	27. GENERAL TRANSFER AGREEMENTS				50,690	50,690	
35	**28. TOTAL TRANSMISSION COSTS**				**173,162**	**173,162**	
36							
37	**29. TOTAL PBL REVENUE REQUIREMENT**		**165,823**	**166,806**	**4,491,291**	**4,996,330**	
38	30. BPA TRANSMISSION REVENUE REQUIREMENT		150,888	57,893	525,233	734,014	
39	(Net of Line 25)						

Table 2.3.2

COSA 06 - FY2011

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2011

($ 000)

	A	B	C	D	E	F
	INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**	
1. GENERATION COSTS						
2. FEDERAL BASE SYSTEM						
3. HYDRO	0	136,952	41,674	454,344	632,971	
4. BPA FISH & WILDLIFE PROGRAM	243,903	21,102	6,422	272,623	300,147	
5. TROJAN				2,300	2,300	
6. WNP #1				165,500	165,500	
7. WNP #2				592,762	592,762	
8. WNP #3				164,849	164,849	
9. SYSTEM AUGMENTATION				304,818	495,078	190,261
10. BALANCING POWER PURCHASES				51,706	51,706	
11. TOTAL FEDERAL BASE SYSTEM	**243,903**	**158,054**	**48,096**	**2,008,901**	**2,405,312**	
12. NEW RESOURCES						
13. IDAHO FALLS				2,819	2,819	
14. COWLITZ FALLS				14,381	14,381	
15. OTHER NEW RESOURCES PURCHASES				67,371	67,371	
16. TOTAL NEW RESOURCES				**84,571**	**84,571**	
17. RESIDENTIAL EXCHANGE				2,235,180	2,235,180	
18. CONSERVATION		12,551	3,819	175,781	192,151	
19. OTHER GENERATION COSTS						
20. BPA PROGRAMS	12,887	1,115	339	153,320	154,774	
21. WNP #3 PLANT				0	0	
22. TOTAL OTHER GENERATION COSTS	**12,887**	**1,115**	**339**	**153,320**	**154,774**	
23. TOTAL GENERATION COSTS	**256,790**	**171,720**	**52,254**	**4,657,752**	**5,071,988**	
24. TRANSMISSION COSTS						
25. TBL TRANSMISSION/ANCILLARY SERVICES				118,230	118,230	
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000	
27. GENERAL TRANSFER AGREEMENTS				51,340	51,340	
28. TOTAL TRANSMISSION COSTS				**170,570**	**170,570**	
29. TOTAL PBL REVENUE REQUIREMENT		**171,720**	**52,254**	**4,828,322**	**5,242,558**	
30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25)		166,505	57,581	548,866	772,952	

Table 2.3.3

COSA 07

Functionalization of Residential Exchange Costs:

	($ Thousands)
Gross Residential Exchange Cost	$ 4,403,593
Residential Exchange Transmission	$ 333,515
Functionalized Residential Exchange Costs	$ 4,070,078

Table 2.3.4

COSA 08

COST OF SERVICE ANALYSIS
Classified Revenue Requirement
Test Period October 2009 - September 2011

($ 000)

	Total Revenue Requirement	Energy Percent	Energy Total	Demand Percent	Demand Total	Load Variance Percent	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 1,334,703	93.22%	$ 1,244,269	5.88%	$ 78,462	0.90%	$ 11,971
4. BPA FISH & WILDLIFE PROGRAM	$ 598,688	94.12%	$ 563,493	5.88%	$ 35,195		
5. TROJAN	$ 4,500	94.12%	$ 4,235	5.88%	$ 265		
6. WNP #1	$ 329,088	94.12%	$ 309,743	5.88%	$ 19,346		
7. WNP #2	$ 1,096,294	93.22%	$ 1,022,015	5.88%	$ 64,447	0.90%	$ 9,833
8. WNP #3	$ 304,553	94.12%	$ 286,649	5.88%	$ 17,904		
9. SYSTEM AUGMENTATION	$ 844,068	93.22%	$ 786,878	5.88%	$ 49,620	0.90%	$ 7,571
10. BALANCING POWER PURCHASES	$ 114,994	93.22%	$ 107,202	5.88%	$ 6,760	0.90%	$ 1,031
11. TOTAL FEDERAL BASE SYSTEM	**$ 4,626,889**		**$ 4,324,485**		**$ 271,998**		**$ 30,406**
12. NEW RESOURCES							
13. IDAHO FALLS	$ 5,606				$ 330		$ 50
14. COWLITZ FALLS	$ 28,735	93.22%	$ 26,788	5.88%	$ 1,689	0.90%	$ 258
15. OTHER NEW RESOURCES PURCHASES	$ 134,090	93.22%	$ 125,005	5.88%	$ 7,883	0.90%	$ 1,203
16. TOTAL NEW RESOURCES	**$ 168,432**		**$ 151,793**		**$ 9,901**		**$ 1,511**
17. RESIDENTIAL EXCHANGE	$ 4,070,078	100.00%	$ 4,070,078				
18. CONSERVATION	$ 389,870	94.12%	$ 366,951	5.88%	$ 22,919		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 306,372	93.22%	$ 285,614	5.88%	$ 18,010	0.90%	$ 2,748
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	**$ 306,372**		**$ 285,614**		**$ 18,010**		**$ 2,748**
23. TOTAL GENERATION COSTS	**$ 9,561,640**		**$ 9,204,147**		**$ 322,829**		**$ 34,665**
24. TRANSMISSION COSTS:							
25. TBL TRANSMISSION/ANCILLARY SERV	$ 239,702	100.00%	$ 239,702				
26. 3RD PARTY TRANS/ANCILLARY SERVI	$ 2,000	100.00%	$ 2,000				
27. GENERAL TRANSFER AGREEMENTS	$ 102,030	100.00%	$ 102,030				
28. TOTAL TRANSMISSION COSTS	**343,732**		**343,732**				
29. TOTAL PBL REVENUE REQUIREMENT	**$ 9,905,372**		**$ 9,547,879**		**$ 357,493**		

Table 2.3.5

COSA 09

COST OF SERVICE ANALYSIS
Functionalized Revenue Credits
Test Period October 2009 - September 2011

	FY 2010	FY 2011	Total
	($ 000)		
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 17,842
4(h)(10)(c) Credit	$ 88,705	$ 89,975	$ 178,680
Colville & Spokane Settlements	$ 4,600	$ 4,600	$ 9,200
Network Wind Integration&Shaping	$ 1,905	$ 1,905	$ 3,810
Misc. Revenues	$ 3,420	$ 3,420	$ 6,840
Green Tags	$ 5,040	$ 5,040	$ 10,081
Ancillary Product Revenue	$ 180,452	$ 215,811	$ 396,263
Ad Hoc Adjustment to Gen Inputs	$ (34,620)	$ (34,620)	$ (69,240)
Totals	$ 258,424	$ 295,052	$ 553,476

Table 2.3.6

COSA 09A

COST OF SERVICE ANALYSIS
Allocation of EE Revenue Credits to Conservation Costs
Test Period October 2009 - September 2011

	FY 2010	FY 2011	Total
	($ 000)		
Conservation Expense Before EE Revenues	$ 197,719	$ 192,151	$ 389,870
Energy Efficiency Revenues	$ (20,500)	$ (20,500)	$ (41,000)
Net Conservation Expense	$ 177,219	$ 171,651	$ 348,870

Table 2.4.1

ALLOCATE 01

Energy Allocation Factors with Residential Exchange Included
Average Megawatts

	FY 2010	FY 2011	Total
Federal Base System			
Total Usage			
Priority Firm..............................	12,039	12,119	24,158
Industrial Firm...........................	413	413	827
New Resource Firm...................	0	0	0
Surplus Firm Other....................	613	586	1,199
Total...	**13,065**	**13,118**	**26,183**
Federal Base System			
Priority Firm..............................	8,399	8,399	16,798
Industrial Firm...........................	0	0	0
New Resource Firm...................	0	0	0
Surplus Firm Other....................	0	0	0
Total...	**8,399**	**8,399**	**16,798**
Residential Exchange			
Priority Firm..............................	3,640	3,720	7,360
Industrial Firm...........................	374	373	747
New Resource Firm...................	0	0	0
Surplus Firm Other....................	555	528	1,083
Total...	**4,569**	**4,621**	**9,189**
New Resource			
Priority Firm..............................	0	0	0
Industrial Firm...........................	44	45	88
New Resource Firm...................	0	0	0
Surplus Firm Other....................	65	63	128
Total...	**108**	**108**	**216**
Conservation			
Priority Firm..............................	12,039	12,119	24,158
Industrial Firm...........................	413	413	827
New Resource Firm...................	0	0	0
Surplus Firm Other....................	613	586	1,199
Total...	**13,065**	**13,118**	**26,183**

Table 2.4.2

ALLOCATE 02

Initial Rate Pool Cost Allocations

($ 000)

	FY 2010	FY 2011	Total
CLASSES OF SERVICE:			
Priority Firm - Preference			
FBS	$ 2,221,576	$ 2,405,312	$ 4,626,889
NR	$ -	$ -	$ -
Exchange	$ 1,595,452	$ 1,664,414	$ 3,259,866
Conservation 1/	$ 163,296	$ 158,579	$ 321,875
BPA programs	$ 299,247	$ 300,567	$ 599,814
Total	**$ 4,279,572**	**$ 4,528,872**	**$ 8,808,444**
Industrial Firm Power			
FBS	$ -	$ -	$ -
NR	$ 33,771	$ 34,992	$ 68,762
Exchange	$ 163,956	$ 166,771	$ 330,727
Conservation 1/	$ 5,607	$ 5,409	$ 11,015
BPA programs	$ 10,274	$ 10,251	$ 20,526
Total	**$ 213,608**	**$ 217,422**	**$ 431,030**
New Resources Firm			
FBS	$ -	$ -	$ -
NR	$ 0.0	$ 0.0	$ 0.0
Exchange	$ 0.0	$ 0.0	$ 0.1
Conservation 1/	$ 0.0	$ 0.0	$ 0.0
BPA programs	$ 0.0	$ 0.0	$ 0.0
Total	**$ 0.1**	**$ 0.1**	**$ 0.1**
Surplus Firm Power			
FBS	$ -	$ -	$ -
NR	$ 50,090	$ 49,580	$ 99,670
Exchange	$ 243,187	$ 236,298	$ 479,485
Conservation 1/	$ 8,316	$ 7,663	$ 15,979
BPA programs	$ 15,239	$ 14,525	$ 29,764
Total	**$ 316,832**	**$ 308,066**	**$ 624,898**
Grand Total	**$ 4,810,012**	**$ 5,054,360**	**$ 9,864,372**

1/ Note: Conservation expense from COSA 06 Tables reduced by EE Revenues in Table COSA 09A.

	A	B	C	D	E
1	**Table 2.5.1**				
2					**RDS 05**
3	**RATE DESIGN STUDY**				
4	**Average Cost of Nonfirm Energy**				
5	**Test Period October 2009 - September 2011**				
6					
7	Generation Costs:			**($ 000)**	
8	Federal Base System			$ 4,626,889	
9	New Resources			$ 168,432	
10	Exchange			$ 4,070,078	
11	Conservation and EE			$ 389,870	
12	BPA Programs			$ 306,372	
13	Total Generation Costs			$ 9,561,640	
14	Transmission Costs For Firm Power			$ 1,010,858	
15	Transmission Costs For Nonfirm Pwr			$ 239,702	
16	Total Costs			$ 10,812,201	
17					
18	Firm Power Sales:			**(GWh)**	
19	Priority Firm			205,818	
20	Industrial Power/Variable Industrial			7,053	
21	New Resources			0.002	
22	Other Obligations			20,516	
23	FPS Pre-Sub., Slice Block, Rate Mitigation Contract Sales			3,370	
24	Total Firm			236,757	
25	Projected Trading Flr Sales			37,290	
26	Total Sales			274,047	
27					
28	Average Cost of Nonfirm (mills/kwh)			39.45	
29					
30					
31	**Table 2.5.2**				
32					**RDS 06**
33	**RATE DESIGN STUDY**				
34	**Bonneville Average System Cost (BASC)**				
35	**Test Period October 2009 - September 2011**				
36					
37	Revenue Requirement:			**($ Thousands)**	
38	Cost of Service Analysis			$ 11,745,854	
39	Applicable Revenue Credits			$ (263,642)	
40	Total			$ 11,482,211	
41					
42	Sales:			**(GWh)**	
43	Firm Power			236,757	
44	Nonfirm Energy			37,290	
45	Total			274,047	
46					
47	Bonneville Average System Cost (mills/kwh):			41.90	
48					
49					
50					
51					
52					

Table 2.5.3

RDS 11

Rate Design Study
Allocation of Secondary and Other Revenue Credits
Test Period October 2009 - September 2011

($ 000)

	FY 2010	FY 2011	Total
Forecast of Secondary Revenues	**$ 775,132**	**$ 904,674**	**$ 1,679,807**
7b3 Costs Allocated to Secondary Revenues	**$ (183,927)**	**$ (184,105)**	**$ (368,032)**
Secondary Revenues After 7b3 Allocation	**$ 591,206**	**$ 720,569**	**$ 1,311,775**

Allocation of Secondary Revenues Credit			
Priority Firm..	$ (591,206)	$ (720,569)	$ (1,311,775)
Industrial Firm..	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -
Total..	**$ (591,206)**	**$ (720,569)**	**$ (1,311,775)**

	FY 2010	FY 2011	Total
Total Other Revenue Credits	**$ 258,424**	**$ 295,052**	**$ 553,476**

Allocation of Other Revenue Credits			
Priority Firm..	$ (258,424)	$ (295,052)	$ (553,476)
Industrial Firm..	$ -	$ -	$ -
New Resource Firm...	$ -	$ -	$ -
Surplus Firm Other..	$ -	$ -	$ -
Total..	**$ (258,424)**	**$ (295,052)**	**$ (553,476)**

Table 2.5.4

RDS 17

Rate Design Study
Calculation of FPS (Surplus)/Shortfall
Test Period October 2009 - September 2011

($ 000)

FPS (Surplus)/Shortfall	**FY 2010**	**FY 2011**	**Total**
Costs allocated to FPS contract sales	$ 316,832	$ 308,066	$ 624,898
Expected Revenue from FPS contract sales	$ (99,492)	$ (89,795)	$ (189,287)
FPS Pre-Sub Contract Revenue	$ (38,281)	$ (35,895)	$ (74,176)
(Surplus)/Shortfall	**$ 179,059**	**$ 182,376**	**$ 361,435**
Secondary Revenues allocated to FPS	$ -	$ -	$ -
Revenue Credits allocated to FPS	$ -	$ -	$ -
FPS (Surplus)/Shortfall	**$ 179,059**	**$ 182,376**	**$ 361,435**

Rate Design Study
Allocation of FPS (Surplus)/Shortfall
Test Period October 2009 - September 2011

($ 000)

Allocation of FPS (Surplus)/Shortfall	**FY 2010**	**FY 2011**	**Total**
Priority Firm..	$ 179,059	$ 182,376	$ 361,435
Industrial Firm..	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -
Surplus Firm Other...	$ (179,059)	$ (182,376)	$ (361,435)
Total..	**$ -**	**$ -**	**$ -**

Table 2.5.5

RDS 19

Rate Design Study
Summary of Initial Cost Allocations
Test Period October 2009 - September 2011

($ 000)

	B	E	F	G
9		**FY 2010**	**FY 2011**	**Total**
10				
11	**Allocation of Revenue Requirement**			
12	Priority Firm..	$ 4,279,572	$ 4,528,872	$ 8,808,444
13	Industrial Firm..	$ 213,608	$ 217,422	$ 431,030
14	New Resource Firm...................................	$ 0	$ 0	$ 0
15	Surplus Firm Other....................................	$ 316,832	$ 308,066	$ 624,898
16	**Total...**	**$ 4,810,012**	**$ 5,054,360**	**$ 9,864,372**
17				
18	**Allocation of Secondary Revenues Credit**			
19	Priority Firm..	$ (591,206)	$ (720,569)	$ (1,311,775)
20	Industrial Firm..	$ -	$ -	$ -
21	New Resource Firm...................................	$ -	$ -	$ -
22	Surplus Firm Other....................................	$ -	$ -	$ -
23	**Total...**	**$ (591,206)**	**$ (720,569)**	**$ (1,311,775)**
24				
25	**Allocation of other Revenues Credits**			
26	Priority Firm..	$ (258,424)	$ (295,052)	$ (553,476)
27	Industrial Firm..	$ -	$ -	$ -
28	New Resource Firm...................................	$ -	$ -	$ -
29	Surplus Firm Other....................................	$ -	$ -	$ -
30	**Total...**	**$ (258,424)**	**$ (295,052)**	**$ (553,476)**
31				
32	**Allocation of FPS (Surplus)/Shortfall**			
33	Priority Firm..	$ 179,059	$ 182,376	$ 361,435
34	Industrial Firm..	$ -	$ -	$ -
35	New Resource Firm...................................	$ -	$ -	$ -
36	Surplus Firm Other....................................	$ (179,059)	$ (182,376)	$ (361,435)
37	**Total...**	**$ -**	**$ -**	**$ -**
38				
39	**Low Density Discount Expenses......**			
40	Priority Firm..	$ 28,303	$ 28,646	$ 56,948
41				
42	**Irrigation Rate Mitigation...................**			
43	Priority Firm..	$ 12,036	$ 12,036	$ 24,072
44				
45	**Initial Allocation to Rate Pools..........**			
46	Priority Firm..	$ 3,649,340	$ 3,736,308	$ 7,385,648
47	Industrial Firm..	$ 213,608	$ 217,422	$ 431,030
48	New Resource Firm...................................	$ 0	$ 0	$ 0
49	Surplus Firm Other....................................	$ 137,774	$ 125,690	$ 263,463
50	**Total...**	**$ 4,000,721**	**$ 4,079,420**	**$ 8,080,142**

Table 2.5.6

RDS 21

Rate Design Study
7(c)(2) Delta Calculation
Test Period October 2009 - September 2011

		FY 2010	FY 2011	Total
1	IP Allocated Costs	$ 213,608	$ 217,422	$ 431,030
2	IP Revenues @ Net Margin	$ 2,000	$ 2,006	$ 4,006
3	adjustment	$ (1,294)	$ (1,296)	$ (2,590)
4	IP Marginal Cost Rate Revenues	$ 186,906	$ 187,484	$ 374,391
5	PF Marginal Cost Rate Revenues	$ 5,640,114	$ 5,681,933	$ 11,322,047
6	PF Allocated Energy Costs	$ 3,649,340	$ 3,736,308	$ 7,385,648
7	Numerator: 1-2-3-((4/5)*6)	$ 91,967	$ 93,427	$ 185,394
8				
9	PF Allocation Factor for Delta	12,372	12,537	24,909
10	NR Allocation Factor for Delta	0.0001	0.0001	0.0002
11	Total Allocation Factors for Delta	12,372	12,537	24,909
12	Denominator: 1.0 + ((9/11)*(4/5))	1.033	1.033	1.033
13				
14	DELTA: (Numerator / Denominator)	**$ 89,017**	**$ 90,443**	**$ 179,460**

Rate Design Study
7(c)(2) Delta allocation
Test Period October 2009 - September 2011

	FY 2010	FY 2011	Total
IP-PF Link Allocations:......................			
Priority Firm...	$ 89,017	$ 90,443	179,460
Industrial Firm......................................	$ (89,017)	$ (90,443)	(179,460)
New Resource Firm..............................	$ 0.001	$ 0.001	0.002
Surplus Firm Other...............................	$ -	$ -	-
Total..	**$ (0.000)**	**$ 0.000**	**(0.000)**

	FY 2010	FY 2011	Total
Allocation to Rate Pools after Link...			
Priority Firm Preference........................	$ 2,319,643	$ 2,367,758	$ 4,687,401
Priority Firm Exchange.........................	$ 1,418,714	$ 1,458,993	$ 2,877,707
Industrial Firm......................................	$ 124,591	$ 126,979	$ 251,570
New Resource Firm..............................	$ 0	$ 0	$ 0
Surplus Firm Other...............................	$ 137,774	$ 125,690	$ 263,463
Total..	**$ 4,000,721**	**$ 4,079,420**	**$ 8,080,142**

Table 2.5.7

RDS 23

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Calculation
Test Period October 2009 - September 2011
($ Thousands)

		A	B	C	D	E	F
		DEMAND		**ENERGY**		**Customer**	**Total/**
		Winter	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
		(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
1	IP Billing Determinants[1]	4,020	5,628	4,100	2,952	9,648	7,053
2	IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3	Revenue	18,572	12,438	60,276	36,018	70,816	198,120
4	Exchange Adj Clause for OY 1985						
5	New ASC Effective Jul 1, 1984						
6	Actual Total Exchange Cost (AEC)	938,442					
7	Actual Exchange Revenue (AER)	772,029					
8	Forecasted Exchange Cost (FEC)	1,088,690					
9	Forecasted Exchange Revenue (FER)	809,201					
10	Total Under/Over-recovery (TAR)						
11	(TAR=(AEC-AER)-(FEC-FER))	(113,076)					
12	Exchange Cost Percentage for IP (ECP)	0.521					
13	Rebate or Surcharge for IP (CCEA=TAR*ECP)	(58,913)					
14	OY 1985 IP Billing Determinants[2]	24,368					
15	OY 1985 DSI Transmission Costs[3]	92,960					
16	Adjustment for Transmission Costs[4]	(3.81)					
17	Adjustment for the Exchange (mills/kWh)[5]	(2.42)					
18	Adjustment for the Deferral (mills/kWh)[6]	(0.90)					
19	IP-83 Average Rate (mills/kWh)[7]	28.09					
20	Floor Rate (mills/kWh)[8]	20.96					

Note 1 - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.
Note 2 - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).
Note 3 - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).
Note 4 - Line 15 / Line 14
Note 5 - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants
Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).
Note 7 - Total Revenue Col F, divided by IP Billing Determinants, Col F
Note 8 - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19

Table 2.5.8

RDS 24

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Test
Test Period October 2009 - September 2011
($ Thousands)

	A	B	C	D	E	F
	Unbundled Requirements Products	Total Transmission	Total Generation Demand	Total Energy	TOTALS	Average Rate
1 IP Billing Determinants				7,053		
2 Floor Rate (mills/kWh)				20.96		
3 Value of Reserves Credit (mills/kWh)						
4 Revenue at Floor Rate Less VOR Credit				147,852	147,852	20.96
5 IP Revenue Under Proposed Rates	0	0	18,387	238,111	256,498	36.37
6 Difference[1]					0	

Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.

Table 2.5.9

RDS 30

Rate Design Study
Calculation of 7(b)(2) Protection Amount
Test Period October 2009 - September 2011

Section 7(b)(2) Rate Test Trigger	**8.07**		
	FY 2010	**FY 2011**	**Total**
Total PF Preference Load (GWH)	63,643	63,885	127,528
PF Preference Protection Amount	$ 513,595	$ 515,555	$ 1,029,150

Table 2.5.9A

RDS 31

Rate Design Study
Calculation of 7(b)(3) Protection Amount Allocation
Test Period October 2009 - September 2011

		FY 2010	**FY 2011**	**Total**
7b2 Protection Allocation................................				
Priority Firm Preference....................................		$ (513,595)	$ (515,555)	$ (1,029,150)
Priority Firm Exchange......................................		$ 302,318	$ 304,234	$ 606,551
Industrial Firm...		$ 27,351	$ 27,216	$ 54,567
New Resource Firm...		$ 0	$ 0	$ 0
Surplus Firm Other..		$ -	$ -	$ -
Reduction in Secondary Revenue Credit	1/	$ 183,927	$ 184,105	$ 368,032
Total...		**$ -**	**$ -**	**$ -**
Allocation to Rate Pools after 7b2..................				
Priority Firm Preference....................................		$ 1,806,047	$ 1,852,204	$ 3,658,251
Priority Firm Exchange......................................		$ 1,721,032	$ 1,763,226	$ 3,484,258
Industrial Firm...		$ 151,942	$ 154,195	$ 306,137
New Resource Firm...		$ 0	$ 0	$ 0
Surplus Firm Other..		$ 137,774	$ 125,690	$ 263,463
Total...		**$ 3,816,795**	**$ 3,895,315**	**$ 7,712,110**

1/ See Table 2.5.3

Table 2.5.10

RDS 33

Rate Design Study
7(b)(2) industrial Adjustment 7(c)(2) Delta Calculation
Test Period October 2009 - September 2011

			FY 2010		FY 2011		Total
1	IP Allocated Costs after 7c2 adjustment	$	124,591	$	126,979	$	251,570
2	IP share of 7b2 adjustment	$	27,351	$	27,216	$	54,567
3	**Total IP revenue requirement**	**$**	**151,942**	**$**	**154,195**	**$**	**306,137**
4							
5	IP revenues at PF preference rate	$	96,138	$	98,340	$	194,478
6	IP Revenues @ Net Margin	$	2,000	$	2,006	$	4,006
7	IP share of 7b2 adjustment	$	27,351	$	27,216	$	54,567
8	**Total IP revenue requirement**	**$**	**125,490**	**$**	**127,561**	**$**	**253,051**
	DELTA: (3 - 8)	**$**	**26,452**	**$**	**26,634**	**$**	**53,086**

		FY 2010		FY 2011		Total
IP-PF Linc 2 Allocation..						
Priority Firm Preference..	$	-	$	-		
Priority Firm Exchange...	$	26,452	$	26,634	$	53,086
Industrial Firm..	$	(26,452)	$	(26,634)	$	(53,086)
New Resource Firm...	$	-	$	-	$	-
Surplus Firm Other..	$	-	$	-	$	-
Total...	**$**	**(0)**	**$**	**(0)**	**$**	**(0)**
Allocation to Rate Pools after IP-PF Linc 2.......................						
Priority Firm Preference..	$	1,806,047	$	1,852,204	$	3,658,251
Priority Firm Exchange...	$	1,747,484	$	1,789,860	$	3,537,344
Industrial Firm..	$	125,490	$	127,561	$	253,051
New Resource Firm...	$	0	$	0	$	0
Surplus Firm Other..	$	137,774	$	125,690	$	263,463
Total...	**$**	**3,816,795**	**$**	**3,895,315**	**$**	**7,712,110**

Table 2.6.1

SLICESEP 01

Rate Design Study
Slice PF Product Separation
Test Period October 2009 - September 2011

Row		FY 2010	FY 2011	Total
7		**FY 2010**	**FY 2011**	**Total**
8				
9	**Slice Revenue requirement...**	$ 620,444	$ 623,214	$ 1,243,658
10	**Slice Revenue Credits...**	$ (61,543)	$ (69,831)	$ (131,374)
11	**Net Slice PF Product Revenue Requirement**	**$ 558,901**	**$ 553,383**	**$ 1,112,285**
12				
13	**Slice Implementation Expenses ....**	$ 2,830	$ 2,830	$ 5,660
14				
15	**Amount to Allocate**	$ 558,901	$ 553,383	$ 1,112,285
16				
17				
18	**Allocation of Slice Revenues..**			
19				
20	Priority Firm Preference..	$ (558,901)	$ (553,383)	$ (1,112,285)
21	Priority Firm Exchange..	$ -	$ -	$ -
22	Industrial Firm..	$ -	$ -	$ -
23	New Resource Firm..	$ -	$ -	$ -
24	Surplus Firm Other...	$ -	$ -	$ -
25	**Total..**	**$ (558,901)**	**$ (553,383)**	**$ (1,112,285)**
26				
27				
28				
29	**Slice Secondary Revenue Credit Adjustment**	$ 175,395	$ 204,708	$ 380,103
30				
31	Priority Firm Preference..	$ 175,395	$ 204,708	$ 380,103
32	Priority Firm Exchange..	$ -	$ -	$ -
33	Industrial Firm..	$ -	$ -	$ -
34	New Resource Firm..	$ -	$ -	$ -
35	Surplus Firm Other...	$ -	$ -	$ -
36	**Total..**	**$ 175,395**	**$ 204,708**	**$ 380,103**
37				
38				
50				
51		**FY 2010**	**FY 2011**	**Total**
52	**Allocation to Rate Pools after Slice Separation Step............................**			
53	Priority Firm Preference..	$ 1,422,541	$ 1,503,528	$ 2,926,070
54	Priority Firm Exchange..	$ 1,747,484	$ 1,789,860	$ 3,537,344
55	Industrial Firm..	$ 125,490	$ 127,561	$ 253,051
56	New Resource Firm..	$ 0	$ 0	$ 0
57	Surplus Firm Other...	$ 137,774	$ 125,690	$ 263,463
58	**Total..**	**$ 3,433,289**	**$ 3,546,640**	**$ 6,979,928**
59				

Table 2.6.2

SLICESEP 02

Rate Design Study
After Slice Separation 7(c)(2) Delta Calculation
Test Period October 2009 - September 2011

			FY 2010		FY 2011		Total
1	IP Allocated Costs	$	213,608	$	217,422	$	431,030
2	IP Revenues @ Net Margin	$	2,000	$	2,006	$	4,006
3	adjustment	$	113,189	$	114,763	$	227,952
4	IP Marginal Cost Rate Revenues	$	186,906	$	187,484	$	374,391
5	PF Marginal Cost Rate Revenues	$	2,683,527	$	2,718,825	$	5,402,352
6	PF Allocated Energy Costs	$	1,422,541	$	1,503,528	$	2,926,070
7	Numerator: 1-2-3-((4/5)*6)		(661)		(3,027)		(3,709)
8							
9	PF Allocation Factor for Delta		5,790		5,864		11,655
10	NR Allocation Factor for Delta		0.0001		0.0001		0.0002
11	Total Allocation Factors for Delta		5,790		5,864		11,655
12	Denominator: 1.0 + ((9/11)*(4/5))		1.0696		1.0690		1.0693
13							
14	DELTA: (Numerator / Denominator)		(618)		(2,832)		(3,449)

Rate Design Study
After Slice Separation 7(c)(2) Delta allocation
Test Period October 2009 - September 2011

		FY 2010		FY 2011		Total
IP-PF Link 3 Allocations:....................						
Priority Firm...	$	(618)	$	(2,832)	$	(3,449)
Industrial Firm.......................................	$	-	$	-	$	-
New Resource Firm...............................	$	618	$	2,832	$	3,449
Surplus Firm Other................................	$	-	$	-	$	-
Total...	**$**	**-**	**$**	**-**	**$**	**-**

		FY 2010		FY 2011		Total
Allocation to Rate Pools after Link 3....................................						
Priority Firm Preference.........................	$	1,421,924	$	1,500,697	$	2,922,620
Priority Firm Exchange..........................	$	1,747,484	$	1,789,860	$	3,537,344
Industrial Firm.......................................	$	126,107	$	130,393	$	256,500
New Resource Firm...............................	$	0	$	0	$	0
Surplus Firm Other................................	$	137,774	$	125,690	$	263,463
Total...	**$**	**3,433,289**	**$**	**3,546,640**	**$**	**6,979,928**

Table 2.7

PF 2010-11

Rate Design Study
Calculation of Priority Firm Preference Rate Components
Test Period October 2009 - September 2011

COMPROMISE PF PREFERENCE RATE SHAPE

Energy Mills/kwh	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.21	2.36	2.48	2.10	2.14	1.99	1.87	1.55	1.42	1.74	2.04	2.10

LV Rate 0.53

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy		
HLH	4,593	5,059	5,809	5,766	5,286	5,271	4,658	4,482	4,482	4,693	4,880	4,451	99294	33098	3778
LLH	2,960	3,568	3,997	4,141	3,453	3,340	2,988	3,222	2,812	3,301	3,049	3,034			
Demand	12,739	13,995	15,192	15,971	15,557	13,803	12,505	11,228	10,842	12,317	11,871	11,664			
											LV Billing Determinant		73754264		

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 155,107	$ 182,236	$ 218,371	$ 184,007	$ 172,259	$ 159,346	$ 132,139	$ 106,212	$ 96,139	$ 123,992	$ 151,002	$ 142,163	$ 2,707,513	$ 2,580,918	95.32%
LLH	$ 73,224	$ 93,724	$ 110,226	$ 95,578	$ 80,489	$ 74,004	$ 60,930	$ 52,773	$ 32,026	$ 63,841	$ 69,970	$ 77,753			
Demand	$ 28,153	$ 33,029	$ 37,676	$ 33,540	$ 33,291	$ 27,467	$ 23,384	$ 17,403	$ 15,396	$ 21,431	$ 24,216	$ 24,495	$ 319,482	$ 304,441	95.32%
												LV Revenue	$ 39,090	$ 37,261	95.32%
													$ 3,066,084	$ 2,922,620	95.32%

PF rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
HLH	**32.19**	**34.33**	**35.83**	**30.42**	**31.07**	**28.82**	**27.04**	**22.59**	**20.45**	**25.18**	**29.49**	**30.45**
LLH	**23.58**	**25.04**	**26.29**	**22.00**	**22.22**	**21.12**	**19.44**	**15.61**	**10.86**	**18.44**	**21.88**	**24.43**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**
											LV Rate	**0.510**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 147,850	$ 173,686	$ 208,147	$ 175,415	$ 164,225	$ 151,914	$ 125,944	$ 101,237	$ 91,657	$ 118,172	$ 143,925	$ 135,532	$ 2,580,874
LLH	$ 69,790	$ 89,336	$ 105,071	$ 91,106	$ 76,725	$ 70,531	$ 58,091	$ 50,292	$ 30,536	$ 60,870	$ 66,708	$ 74,112	
Demand	$ 26,879	$ 31,489	$ 35,853	$ 31,943	$ 31,735	$ 26,225	$ 22,258	$ 16,617	$ 14,637	$ 20,446	$ 23,029	$ 23,329	$ 304,441
												LV Revenue	$ 37,615
													$ 2,922,929

Non-Slice PF Average Rate

Energy Costs	**$ 2,580,918**	**25.99**
Demand Costs	**$ 304,441**	**3.07**
Unbundled Cost	**$ 37,261**	**0.38**
Total	**$ 2,922,620**	**29.43**
Billing Determinants	**99294**	

Table 2.8

Base PFx 2010-11

Rate Design Study
Calculation of Unbifurcated Priority Firm Rate Components
Test Period October 2009 - September 2011

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.11	2.25	2.36	2.00	2.04	1.90	1.78	1.48	1.35	1.66	1.94	2.00

Unbifurcated PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	9,577	10,758	12,588	13,065	11,981	11,579	10,299	9,146	8,444	8,630	9,713	9,794	205,818
LLH	6,031	7,058	8,002	9,026	7,725	7,187	6,287	6,294	5,085	5,725	5,658	6,167	
Demand	28,525	31,084	35,171	38,250	36,766	29,796	27,755	23,820	21,505	24,409	25,365	26,981	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
Energy	$ 472,614	$ 572,905	$ 693,894	$ 625,218	$ 570,542	$ 509,297	$ 420,379	$ 319,854	$ 239,037	$ 338,710	$ 430,370	$ 470,864	$ 5,663,683	$ 6,886,485	121.59%
Demand	$ 60,187	$ 69,938	$ 83,004	$ 76,500	$ 75,002	$ 56,612	$ 49,404	$ 35,253	$ 29,032	$ 40,520	$ 49,208	$ 53,963	$ 678,623	$ 678,623	100.00%
Transmission Costs														$ -	
													$ 6,342,306	$ 7,565,108	

Unbifurcated PF

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy	**36.82**	**39.10**	**40.98**	**34.41**	**35.20**	**33.00**	**30.82**	**25.19**	**21.48**	**28.69**	**34.04**	**35.87**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
Energy	$ 574,652	$ 696,596	$ 843,707	$ 760,203	$ 693,723	$ 619,256	$ 511,140	$ 388,911	$ 290,646	$ 411,839	$ 523,287	$ 572,525	$ 6,886,485
Demand	$ 60,187	$ 69,938	$ 83,004	$ 76,500	$ 75,002	$ 56,612	$ 49,404	$ 35,253	$ 29,032	$ 40,520	$ 49,208	$ 53,963	$ 678,623
Transmission Costs													$ -
													$ 7,565,108

Unbifurcated PF Rate

Energy Costs	$ 6,886,485	33.46
Demand Costs	$ 678,623	3.30
Unbundled Cost	$ -	0.00
Transmission Costs	$ -	0.00
Total	$ 7,565,108	36.76
Billing Determinants	$ 205,818	

Unbifurcated PF	36.76
Transmission Costs	4.26
Delivered Unbifurcated PF	**41.02**

Table 2.9

Rate Design Study

Calculation of Utility Specific Priority Firm Exchange Rates and Net REP Benefits **REP 1**

Test Period October 2009 - September 2011

	A	B	C	D	E	F	G	H	I	J	K
	Utility Load Weighted Average Rate Period ASCs	Delivered Unbifurcated PF Rate	Rate Period Exchange Load GWH	Preliminary Benefits at Unbifurcated PF Rate (A - B) * C	Rate Period Percent of Preliminary Benefits	7b3 and 7c2 Allocation Using Percent of Benefits	Exchange Load GWH	Load Weighted Average Rate Period Supplemental 7b3 Charge F / G	Delivered Unbifurcated PF Rate	Load Weighted Average Utility Specific PF Exchange Rate H + I	Utility Specific Exchange Benefits (A - J) * C
Avista	$ 49.87	$ 41.02	8020	$ 70,981	6.0%	$ 39,481	8020	$ 4.92	$ 41.02	$ 45.94	$ 31,521
Idaho Power	$ 39.25	$ 41.02	0	$ -	0.0%	$ -	0	$ -	$ 41.02	$ 41.02	$ -
Northwestern Energy PNWR	$ 54.57	$ 41.02	1248	$ 16,906	1.4%	$ 9,379	1248	$ 7.52	$ 41.02	$ 48.54	$ 7,524
Pacificorp	$ 51.72	$ 41.02	19170	$ 205,116	17.3%	$ 113,789	19170	$ 5.94	$ 41.02	$ 46.96	$ 91,248
Portland General	$ 59.01	$ 41.02	17588	$ 316,401	26.6%	$ 175,718	17588	$ 9.99	$ 41.02	$ 51.01	$ 140,701
Puget Sound Energy	$ 63.36	$ 41.02	23972	$ 535,533	45.1%	$ 297,534	23972	$ 12.41	$ 41.02	$ 53.43	$ 238,041
Franklin	$ 42.78	$ 41.02	714	$ 1,257	0.1%	$ 697	714	$ 0.98	$ 41.02	$ 42.00	$ 557
Snohomish	$ 46.58	$ 41.02	7578	$ 42,134	3.5%	$ 23,245	7578	$ 3.07	$ 41.02	$ 44.09	$ 18,869
Total/Average				**$ 1,188,329**	**100%**	**$ 659,841**				**$ 49.44**	**$ 528,461**

Note: Values in this table are load weighted values for the rate period. The individual FY 2010 and FY 2011 utility specific PF Exchange rates are found in the rate schedules.

Table 2.9A

Average PFx 2010-11

Rate Design Study
Calculation of Average Priority Firm Exchange Rate Components
Test Period October 2009 - September 2011

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.11	2.25	2.36	2.00	2.04	1.90	1.78	1.48	1.35	1.66	1.94	2.00

PFx billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	3,580	4,069	5,237	5,776	5,420	5,067	4,611	3,068	2,569	2,501	3,311	4,050	78,290
LLH	2,167	2,341	2,945	3,792	3,439	3,061	2,638	1,925	1,399	1,414	1,658	2,252	
Demand	11,893	12,580	15,948	18,062	17,456	12,743	12,484	8,593	7,293	8,325	9,794	11,929	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
Energy	$ 174,508	$ 208,052	$ 278,094	$ 271,823	$ 256,819	$ 221,008	$ 184,589	$ 104,238	$ 71,036	$ 93,417	$ 140,510	$ 187,078	$ 2,191,172	$ 3,248,899	148.27%
Demand	$ 25,095	$ 28,306	$ 37,636	$ 36,124	$ 35,611	$ 24,213	$ 22,221	$ 12,717	$ 9,845	$ 13,819	$ 19,000	$ 23,858	$ 288,446	$ 288,446	100.00%
												Transmission Costs	$ 333,515	$ 333,515	100.00%
													$ 2,813,133	$ 3,870,860	

PF exchange rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
Energy	**45.02**	**48.13**	**50.39**	**42.12**	**42.98**	**40.32**	**37.76**	**30.96**	**26.54**	**35.38**	**41.92**	**44.01**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
Energy	$ 258,747	$ 308,483	$ 412,336	$ 403,039	$ 380,791	$ 327,693	$ 273,694	$ 154,557	$ 105,326	$ 138,512	$ 208,337	$ 277,385	$ 3,248,899
Demand	$ 25,095	$ 28,306	$ 37,636	$ 36,124	$ 35,611	$ 24,213	$ 22,221	$ 12,717	$ 9,845	$ 13,819	$ 19,000	$ 23,858	$ 288,446
												Transmission Costs	$ 333,515
													$ 3,870,860

PF Exchange Average Rate

Energy Costs	$ 3,248,899	41.50
Demand Costs	$ 288,446	3.68
Unbundled Cost	$ -	0.00
Transmission Costs	$ 333,515	4.26
Total	$ 3,870,860	49.44
Billing Determinants	78,290	

IP 2010-11

Table 2.10

Rate Design Study
Calculation of Industrial Firm Power Rate Components
Test Period October 2009 - September 2011

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.11	2.25	2.36	2.00	2.04	1.90	1.78	1.48	1.35	1.66	1.94	2.00

IP billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	340.90	321.60	321.60	334.46	315.17	340.90	328.03	334.46	328.03	328.03	340.90	315.17	7,052.69
LLH	257.68	257.68	276.58	263.71	234.77	256.48	250.85	263.71	250.85	270.14	257.28	263.71	
Demand	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 11,512	$ 11,584	$ 12,089	$ 10,673	$ 10,271	$ 10,305	$ 9,306	$ 7,927	$ 7,036	$ 8,667	$ 10,547	$ 10,066	$ 188,179	$ 238,113	126.54%
LLH	$ 6,375	$ 6,769	$ 7,628	$ 6,086	$ 5,472	$ 5,684	$ 5,115	$ 4,320	$ 2,857	$ 5,225	$ 5,905	$ 6,759			
Demand	$ 1,696	$ 1,809	$ 1,897	$ 1,608	$ 1,640	$ 1,528	$ 1,431	$ 1,190	$ 1,085	$ 1,335	$ 1,560	$ 1,608	$ 18,387	$ 18,387	100.00%
													$ 206,566	$ 256,500	

IP rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**42.73**	**45.58**	**47.56**	**40.38**	**41.24**	**38.25**	**35.90**	**29.99**	**27.14**	**33.43**	**39.15**	**40.42**
LLH	**31.30**	**33.24**	**34.90**	**29.20**	**29.50**	**28.04**	**25.80**	**20.73**	**14.41**	**24.47**	**29.04**	**32.43**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 14,566	$ 14,659	$ 15,295	$ 13,506	$ 12,998	$ 13,039	$ 11,776	$ 10,031	$ 8,903	$ 10,966	$ 13,346	$ 12,739	$ 238,112
LLH	$ 8,065	$ 8,565	$ 9,653	$ 7,700	$ 6,926	$ 7,192	$ 6,472	$ 5,467	$ 3,615	$ 6,610	$ 7,471	$ 8,552	
Demand	$ 1,696	$ 1,809	$ 1,897	$ 1,608	$ 1,640	$ 1,528	$ 1,431	$ 1,190	$ 1,085	$ 1,335	$ 1,560	$ 1,608	$ 18,387
													$ 256,500

IP Average Rate

Energy Costs	$ 238,112.5	33.76
Demand Costs	$ 18,387.5	2.61
Unbundled Cost	$ -	0.00
Total	$ 256,500.0	36.37
Non-Slice Billing Determinants	$ 7,052.7	

Table 2.11

NR 2010-11

Rate Design Study
Calculation of New Resource Rate Components
Test Period October 2009 - September 2011

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	2.11	2.25	2.36	2.00	2.04	1.90	1.78	1.48	1.35	1.66	1.94	2.00

NR billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.002
LLH	0.00006	0.00006	0.00007	0.00007	0.00006	0.00006	0.00006	0.00007	0.00006	0.00007	0.00006	0.00007	
Demand	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.003	$ 0.003	$ 0.047	$ 0.118	251.54%
LLH	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.002			
Demand	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.005	$ 0.005	100.00%
													$ 0.051	$ 0.122	

NR rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**84.95**	**90.61**	**94.56**	**80.27**	**81.98**	**76.04**	**71.36**	**59.62**	**53.96**	**66.46**	**77.83**	**80.34**
LLH	**62.23**	**66.08**	**69.38**	**58.06**	**58.63**	**55.74**	**51.29**	**41.20**	**28.65**	**48.65**	**57.73**	**64.47**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 0.007	$ 0.007	$ 0.008	$ 0.007	$ 0.006	$ 0.006	$ 0.006	$ 0.005	$ 0.004	$ 0.005	$ 0.007	$ 0.006	$ 0.118
LLH	$ 0.004	$ 0.004	$ 0.005	$ 0.004	$ 0.003	$ 0.004	$ 0.003	$ 0.003	$ 0.002	$ 0.003	$ 0.004	$ 0.004	
Demand	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.005
													$ 0.122

NR Average Rate

Energy Costs	$ 0.118	67.12
Demand Costs	$ 0.005	2.61
Unbundled Cost	$ -	0.00
Total	$ 0.122	69.72
Non-Slice Billing Determinants	$ 0.002	

Table 2.12

Flat PF 2010-11

Rate Design Study
Calculation of Flat Priority Firm Preference Rate
Test Period October 2009 - September 2011

PF Preference Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**32.19**	**34.33**	**35.83**	**30.42**	**31.07**	**28.82**	**27.04**	**22.59**	**20.45**	**25.18**	**29.49**	**30.45**
LLH	**23.58**	**25.04**	**26.29**	**22.00**	**22.22**	**21.12**	**19.44**	**15.61**	**10.86**	**18.44**	**21.88**	**24.43**
Demand	**2.11**	**2.25**	**2.36**	**2.00**	**2.04**	**1.90**	**1.78**	**1.48**	**1.35**	**1.66**	**1.94**	**2.00**

Flat Load FY2007-09

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HLH	32.0	29.6	30.4	31.2	29.2	31.6	30.8	30.8	30.8	30.8	31.6	29.6	657.6
LLH	23.8	24.5	25.4	24.6	21.8	24.1	23.2	25.0	23.2	25.0	24.2	24.4	
Demand	75	75	75	75	75	75	75	75	75	75	75	75	

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HLH	$ 1,030	$ 1,016	$ 1,089	$ 949	$ 907	$ 911	$ 833	$ 696	$ 630	$ 776	$ 932	$ 901	$ 16,726
LLH	$ 562	$ 612	$ 668	$ 541	$ 484	$ 510	$ 451	$ 390	$ 252	$ 461	$ 529	$ 596	
Demand	$ 158	$ 169	$ 177	$ 150	$ 153	$ 143	$ 134	$ 111	$ 101	$ 125	$ 146	$ 150	$ 1,715
													$ 18,442

Flat PF Preference Rate FY2007-09 $ 28.04

Table 2.13 (1 of 2)

Slice Costing Table

		FY 2010	FY 2011
1	**Operating Expenses**		
2	**Power System Generation Resources**		
3	**Operating Generation**		
4	COLUMBIA GENERATING STATION (WNP-2)	$ 269,200	$ 365,000
5	BUREAU OF RECLAMATION	$ 87,700	$ 98,550
6	CORPS OF ENGINEERS	$ 193,000	$ 197,911
7	LONG-TERM CONTRACT GENERATING PROJECTS	$ 31,889	$ 32,343
8	**Sub-Total**	**$ 581,789**	**$ 693,804**
9	**Operating Generation Settlement Payment**		
10	COLVILLE GENERATION SETTLEMENT	$ 21,328	$ 21,754
11	**Sub-Total**	**$ 21,328**	**$ 21,754**
12	**Non-Operating Generation**		
13	TROJAN DECOMISSIONING	$ 2,200	$ 2,300
14	WNP-1&3 DECOMISSIONING	$ 418	$ 428
15	**Sub-Total**	**$ 2,618**	**$ 2,728**
16	**Contracted Power Purchases**		
17	DSI MONETIZED BENEFITS	**$ 58,867**	**$ 58,867**
18	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)	$ -	$ -
19	PNCA HEADWATER BENEFITS	$ 2,042	$ 2,620
20	GROSS OTHER POWER PURCHASES (short term - omit)	$ -	$ -
21	**Sub-Total**	**$ 60,909**	**$ 61,487**
22	**Bookout Adjustment to Power Purchases (omit)**		
23	**Augmentation Power Purchases (omit - calculated below)**		
24	AUGMENTATION POWER PURCHASES (omit)		
25	CONSERVATION AUGMENTATION (omit)		
26	**Sub-Total**	**$ -**	**$ -**
27	**Exchanges and Settlements**		
28	PUBLIC RESIDENTIAL EXCHANGE	$ 11,974	$ 7,495
29	IOU RESIDENTIAL EXCHANGE	$ 253,883	$ 258,798
30	OTHER SETTLEMENTS	$ -	$ -
31	**Sub-Total**	**$ 265,857**	**$ 266,293**
32	**Renewable Generation**		
33	RENEWABLES R&D	$ 4,833	$ 6,092
34	RENEWABLES CONSERVATION RATE CREDIT	$ 4,000	$ 2,500
35	RENEWABLES	$ 31,715	$ 32,306
36	**Sub-Total**	**$ 40,548**	**$ 40,898**
37	**Generation Conservation**		
38	GENERATION CONSERVATION R&D	$ -	$ -
39	DSM TECHNOLOGIES	$ 1,600	$ 1,600
40	CONSERVATION ACQUISITION	$ 14,000	$ 14,000
41	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,000	$ 5,000
42	ENERGY EFFICIENCY DEVELOPMENT	$ 20,500	$ 20,500
43	LEGACY	$ 1,988	$ 1,622
44	MARKET TRANSFORMATION	$ 12,000	$ 12,000
45	**Sub-Total**	**$ 55,088**	**$ 54,722**
46	**Conservation and Renewable Discount (C&RD)**		
47	CONSERVATION RATE CREDIT	$ 32,000	$ 32,000
48	CONSERVATION AND RENEWABLE DISCOUNT		
49	**Sub-Total**	**$ 32,000**	**$ 32,000**
50	**Power System Generation Total**	**$ 1,060,137**	**$ 1,173,686**
51	**Power Services Transmission Acquisition and Ancillary Services**		
52	**Transmission Acquisition and Ancillary Services**		
53	TRANSMISSION & ANCILLARY SERVICES		
54	Canadian Entitlement Agreement Transmission Expenses	$ 27,000	$ 27,000
55	PNCA & NTS Transmission and System Obligaton Expenses	$ 1,000	$ 1,000
56	3RD PARTY GTA WHEELING	$ 50,690	$ 51,340
57	3RD PARTY TRANS & ANCILLARY SVCS	$ -	$ -
58	GENERATION INTEGRATION	$ 6,800	$ 6,800
59	TELEMETERING/EQUIP REPLACEMT	$ 50	$ 50
60	**Power Services Trans Acquisition and Ancillary Services Sub-Total**	**$ 85,540**	**$ 86,190**
61			
62	**Power Non-Generation Operations**		
63	**System Operations**		
64	SYSTEM OPERATIONS R&D	$ -	$ -
65	EFFICIENCIES PROGRAM (excludes TMS expenses)	$ -	$ -
66	INFORMATION TECHNOLOGY	$ 6,359	$ 6,324
67	GENERATION PROJECT COORDINATION	$ 7,892	$ 8,118
68	SLICE IMPLEMENTATION (omit - calculated separately)	$ -	$ -
69	**Sub-Total**	**$ 14,251**	**$ 14,442**
70	**Scheduling**		
71	SCHEDULING R&D		
72	OPERATIONS SCHEDULING	$ 9,999	$ 10,350
73	OPERATIONS PLANNING	$ 6,207	$ 6,473
74	**Sub-Total**	**$ 16,206**	**$ 16,823**
75	**Marketing and Business Support**		
76	SALES & SUPPORT	$ 19,391	$ 19,617
77	Contractual exclusion	$ (5,360)	$ (5,360)
78	Implementation Expense Exclusions - Add back	$ -	$ -
79	PUBLIC COMMUNICATION & TRIBAL LIAISON	$ -	$ -
80	STRATEGY, FINANCE & RISK MGMT	$ 17,151	$ 17,632
81	EXECUTIVE AND ADMINISTRATIVE SERVICES	$ 3,645	$ 5,320
82	CONSERVATION SUPPORT (EE staff costs)	$ 9,359	$ 9,947
83	**Sub-Total**	**$ 44,186**	**$ 47,156**
84	**Power Non-Generation Operations Sub-Total**	**$ 74,643**	**$ 78,421**

Table 2.13 (2 of 2)

Slice Costing Table

		FY 2010		FY 2011
85	**Fish and Wildlife/USF&W/Planning Council**			
86	**BPA Fish and Wildlife (includes F&W Shared Services)**			
87	FISH & WILDLIFE	$ 230,000		$ 236,000
88	**Sub-Total**	**$ 230,000**		**$ 236,000**
89	**USF&W Lower Snake Hatcheries**			
90	USF&W LOWER SNAKE HATCHERIES	$ 23,600		$ 24,480
91	**Planning Council**	$ -		$ -
92	PLANNING COUNCIL	$ 9,641		$ 9,838
93	**Environmental Requirements**	$ -		$ -
94	ENVIRONMENTAL REQUIREMENTS	$ 300		$ 300
95	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 263,541**		**$ 270,618**
96	**General and Administrative/Shared Services**			
97	**Additional Post-Retirement Contribution**			
98	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$ 15,598		$ 16,071
99	**BPA Internal Support - G&A and Shared Srv. (excludes direct project support)**	$ -		$ -
##	AGENCY SERVICES G&A	$ 51,877		$ 52,270
##	**Sub-Total BPA Internal Support Services**	**$ 51,877**		**$ 52,270**
##	**Supply Chain - Shared Services**			
##	**General and Administrative/Shared Services Sub-Total**	**$ 67,475**		**$ 68,341**
##	**Bad Debt Expense**	$ -		$ -
##	**Other Income, Expenses, Adjustments**	**$ -**		**$ -**
##	**Non-Federal Debt Service**	$ -		$ -
##	**Energy Northwest Debt Service**	$ -		$ -
##	COLUMBIA GENERATING STATION DEBT SVC	$ 234,333		$ 227,762
##	WNP-1 DEBT SVC	$ 163,171		$ 165,072
##	WNP-3 DEBT SVC	$ 139,704		$ 164,849
##	EN RETIRED DEBT	$ -		$ -
##	EN LIBOR INTEREST RATE SWAP	$ -		$ -
##	**Sub-Total**	**$ 537,208**		**$ 557,683**
##	**Non-EN Debt Service**			
##	COWLITZ FALLS DEBT SVC	$ 11,566		$ 11,563
##	N. WASCO DEBT SVC	$ 2,200		$ 2,196
##	TROJAN DEBT SVC	$ -		$ -
##	CONSERVATION DEBT SVC	$ 5,079		$ 4,924
##	**Sub-Total**	**$ 18,845**		**$ 18,683**
##	**Non-Federal Debt Service Sub-Total**	**$ 556,053**		**$ 576,366**
##	**Depreciation (excludes TMS)**	$ 118,616		$ 119,920
##	**Amortization (excludes ConAug amortization)**	$ 65,783		$ 73,654
##	**Total Operating Expenses**	**$ 2,291,788**		**$ 2,447,196**
##				
##	**Other Expenses**			
##	Net Interest Expense	$ 165,823		$ 171,720
##	LDD	$ 28,303		$ 28,646
##	Irrigation Rate Mitigation Costs	$ 12,036		$ 12,036
##	**Sub-Total**	**$ 206,162**		**$ 212,402**
##	**Total Expenses**	**$ 2,497,950**		**$ 2,659,598**
##				
##	**Revenue Credits**			
##	Ancillary and Reserve Service Revs. Total	$ 180,452		$ 215,811
##	Downstream Benefits and Pumping Power	$ 8,921		$ 8,921
##	4(h)(10)(c)	$ 88,705		$ 89,975
##	Colville and Spokane Settlements	$ 4,600		$ 4,600
##	FCCF	$ -		$ -
##	Energy Efficiency Revenues	$ 20,500		$ 20,500
##	Miscellaneous	$ 3,420		$ 3,420
##	Ad Hoc Adjustemnt	$ (34,620)		$ (34,620)
##	**Total Revenue Credits**	**$ 271,978**		**$ 308,607**
##	**Augmentation Costs**			
##	Residual augmentation cost			
##	Other augmentation cost	$ 176,580		$ 304,818
##	Minus revenues	$ 98,560		$ 156,386
##	**Net Cost of Augmentation**	**$ 131,144**		**$ 95,308**
##				
##				
##	**Minimum Required Net Revenue calculation**			
##	Principal Payment of Fed Debt for Power	$ 267,264		$ 161,888
##	Irrigation assistance	$ -		$ -
##	Depreciation	$ 118,616		$ 119,920
##	Amortization	$ 79,118		$ 86,989
##	Capitalization Adjustment	$ (45,937)		$ (45,937)
##	Bond Premium Amortization	$ 185		$ 185
##	Principal Payment of Fed Debt exceeds non cash expenses	$ 115,282		$ 731
##	Minimum Required Net Revenues	**$ 115,282**		**$ 731**
##				
##	Annual Slice Revenue Requirement (Amounts for each FY)	**$ 2,472,398**		**$ 2,447,030**
##				
##	SLICE TRUE-UP ADJUSTMENT CALCULATION			$ (25,368)
##				
##	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case	**$ 2,459,714**		
##	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)	$ 12,684		$ (12,684)
##	AMOUNT BILLED (22.6278 percent)	$ 2,870		$ (2,870)
##	Slice Implementation Expenses (not incl. in base rate)	$ 2,790		$ 2,870
##	TRUE UP ADJUSTMENT	**$ 5,660**	**FY 2010**	**$ (0)**
##			**True-Up**	
##				
##	**SLICE RATE CALCULATION ($)**			
##	**2010-10 Monthly Slice Revenue Requirement (2-Year total divided by 24 months)**			**$204,976,183**
##	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**			**$2,049,762**
##				
##	**ANNUAL BASE SLICE REVENUES**			**$ 556,579,208**
##	**Annual Slice Implementation Expenses**			**$ 2,830,000**
##				
	TOTAL ANNUAL SLICE REVENUES			**$ 559,409,208**

	A	B	C	D	E
1		**Table 2.14.1**			
2					**RDS 60A**
3		**RATE DESIGN STUDY**			
4		**Allocated Costs and Unit Costs**			
5		**Priority Firm Power (PF)**			
6		**($ Thousands)**			
7		**Test Period October 2009 - September 2011**			
8					
9			**A**	**B**	**C**
10			**ALLOCATED**	**UNIT**	**PERCENT**
11			**COSTS**	**COSTS**	**CONTRIBUTION**
12		GENERATION ENERGY	($ Thousands)	(Mills/KwH)	(Percent)
13					
14		Federal Base System			
15		Hydro	1,334,703	6.485	17.64%
16		Fish & Wildlife	598,688	2.909	7.91%
17		Trojan	4,500	0.022	0.06%
18		WNP #1	329,088	1.599	4.35%
19		WNP #2	1,096,294	5.327	14.49%
20		WNP #3	304,553	1.480	4.03%
21		System Augmentation	844,068	4.101	11.16%
22		Balancing Power Purchases	114,994	0.559	1.52%
23		Total Federal Base System	4,626,889	22.481	61.16%
24		New Resources			
25		Gross Residential Exchange	3,259,866	15.839	43.09%
26		Conservation	321,875	1.564	4.25%
28		BPA Programs	599,814	2.914	7.93%
29		TOTAL COSA ALLOCATIONS	8,808,444	42.797	113.89%
30					
31					
32		Nonfirm Excess Revenue Credit	(1,311,775)	-6.373	-17.34%
33		Low Density Discount Expense	56,948	0.277	0.75%
34		Other Revenue Credits	(553,476)	-2.689	-7.32%
35		Irrigation Rate Mitigation Expense	24,072	0.117	0.32%
36		SP Revenue Surplus/Dfct Adj.	361,435	1.756	4.78%
37		7(c)(2) Delta Adjustment	179,460	0.872	2.37%
38		7(c)(2) Floor Rate Adjustment			
39		TOTAL RATE DESIGN ADJUSTMENTS	(1,243,336)	-6.041	-16.44%
40					
41		Total Generation	7,565,108	**36.76**	100.00%
56					
57		Billing Determinants With LDD Discount	205,818		

Table 2.14.2

RDS 60B

RATE DESIGN STUDY
Allocated Costs and Unit Costs
Priority Firm Power (PF) Bifurcated
($ Thousands)
Test Period October 2009 - September 2011

		A ALLOCATED COSTS	B UNIT COSTS	C PERCENT CONTRIBUTION
Rate Design Step PF Rate		($ Thousands)	(Mills/KwH)	(Percent)
PRIORITY FIRM PREFERENCE				
Revenue Reqmt @ PF Combined Rate		4,687,457	36.756	128.13%
7(b)(2) Credit		(1,029,150)	-8.070	-28.13%
	Subtotal	3,658,307	28.686	100.00%
Floor Rate Adjustment				
	TOTAL	3,658,307	28.686	100.00%
Billing Determinants:				
Total PF Preference Forecasted Sales		127,528	28.686	100.00%
Adjusted for LDD				
Slice Separation Step				
Revenue Reqmt @ Rate Design Step PF Pref.		3,658,307		
Slice PF Product Revenues		(1,112,285)		
Slice Secondary Revenue Credit Adjustment		380,103		
Slice Separation 7c2 Adjustement		(3,449)		
Revenue Reqmt @ Non-Slice PF Pref.		2,922,676		
Non-Slice PF Preference Forecasted Sales		99,294	**29.435**	
PRIORITY FIRM EXCHANGE				
Revenue Reqmt @ PF Combined Rate		2,877,651	36.756	74.34%
7(b)(2) Adjustment		606,551	7.747	15.67%
7(b)(2) Industrial Adjustment		53,086	0.678	1.37%
	Subtotal	3,537,289	45.182	91.38%
Floor Rate Adjustment				
	Total Energy	3,537,289	45.182	91.38%
Total Transmission		333,515	4.260	8.62%
	TOTAL	3,870,804	**49.442**	100.00%
Billing Determinants:				
Forecasted Exchange Loads		78,290	49.442	100.00%

	A/B	C	D	E
1		**Table 2.14.3**		
2				**RDS 61**
3		**RATE DESIGN STUDY**		
4		**Allocated Costs and Unit Costs**		
5		**Industrial Firm Power Rate (IP)**		
6		**($ Thousands/Unit Costs in Mills/KwH, or as Indicated)**		
7		**Test Period October 2009 - September 2011**		
8				
9		**A**	**B**	**C**
10		**ALLOCATED**	**UNIT**	**PERCENT**
11		**COSTS**	**COSTS**	**CONTRIBUTION**
12	GENERATION ENERGY	($ Thousands)	(Mills/KwH)	(Percent)
13				
14	Federal Base System			
15	Hydro			
16	Fish & Wildlife			
17	Trojan			
18	WNP #1			
19	WNP #2			
20	WNP #3			
21	System Augmentation			
22	Balancing Power Purchases			
23	Total Federal Base System			
24	New Resources	68,762	9.750	26.81%
25	Gross Residential Exchange	330,727	46.894	128.94%
26	Conservation	11,015	1.562	4.29%
27	BPA Programs	20,526	2.910	8.00%
28	TOTAL COSA ALLOCATIONS	431,030	61.116	168.04%
29				
30	Nonfirm Excess Revenue Credit			
31				
32	Other Revenue Credits			
33				
34	SP Revenue Surplus/Dfct Adj.			
35	7(c)(2) Delta Adjustment	(179,460)	-25.446	-69.96%
36	7(c)(2) Floor Rate Adjustment			
37	TOTAL RATE DESIGN ADJSTMTS	(179,460)	-25.446	-69.96%
38	Total Generation	251,570	35.670	98.08%
39				
50				
51	Total Allocated & Adjusted Costs	251,570	35.670	98.08%
52				
53	7(b)(2) Adjustments			
54	7(b)(2) Amount	54,567	7.737	21.27%
55	7(b)(2) Industrial Adj.	(53,086)	-7.527	-20.70%
56		253,051	35.880	98.66%
57				
58	Slice Separation Step Adjustment			
59	7(c)(2) Slice Separation Amount	3,449	0.489	1.34%
60	Total With 7(b)(2) Adjustments	256,500	**36.369**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	7,053		

Table 2.14.4

RDS 62

RATE DESIGN STUDY
Allocated Costs and Unit Costs
New Resources Firm Power (NR)
($ Thousands/Unit Costs in Mills/KwH, or as Indicated)
Test Period October 2009 - September 2011

Row		A ALLOCATED COSTS	B UNIT COSTS	C PERCENT CONTRIBUTION
12	GENERATION ENERGY	($ Thousands)	(Mills/KwH)	(Percent)
13				
14	Federal Base System			
15	Hydro			
16	Fish & Wildlife			
17	Trojan			
18	WNP #1			
19	WNP #2			
20	WNP #3			
21	System Augmentation			
22	Balancing Power Purchases			
23	Total Federal Base System			
24	New Resources	0.017	9.750	13.98%
25	Gross Residential Exchange	0.082	46.894	67.26%
26	Conservation	0.003	1.562	2.24%
27	BPA Programs	0.005	2.910	4.17%
28	TOTAL COSA ALLOCATIONS	0.107	61.116	87.65%
29				
30	Nonfirm Excess Revenue Credit			
31				
34	SP Revenue Surplus/Dfct Adj.			
35	7(c)(2) Delta Adjustment	0.002	0.871	1.25%
36	7(c)(2) Floor Rate Adjustment			
37	TOTAL RATE DESIGN ADJSTMTS	0.002	0.871	1.25%
38	Total Generation Energy	0.109	61.986	88.90%
47				
49	Total Allocated & Adjusted Costs	0.109	61.986	88.90%
50	7(b)(2) Adjustments			
51	7(b)(2) Amount	0.014	7.737	11.10%
52	7(b)(2) Industrial Adj.			
53	7(b(2)Exchange Cost Adjustment			
54	Total With 7(b)(2) Adjustments	0.122	**69.72**	100.00%
55				
56	Billing Determinant / Energy (GWh)	0.002		

Table 2.14.5

RDS63

RATE DESIGN STUDY
Rate Design Step Resource Cost Contribution
($ Thousands)
Test Period October 2009 - September 2011

	A	B	C	D	E	F	G	H
	ALLOCATED GENERATION COSTS				**PERCENTAGES**			
	FBS Resources	**Exchange Resources**	**New Resources**	**Total**	**FBS Resources**	**Exchange Resources**	**New Resources**	**Total**
CLASSES OF SERVICE:								
Power Rates								
Priority Firm - Preference	2,866,891	2,019,863		4,886,754	58.67%	41.33%		100.00%
Priority Firm - Exchange	1,759,998	1,240,003		3,000,001	58.67%	41.33%		100.00%
Priority Firm Power - Total	4,626,889	3,259,866		7,886,754	58.67%	41.33%		100.00%
Industrial Firm Power		330,727	68,762	399,489		82.79%	17.21%	100.00%
New Resources Firm		0	0	0		82.79%	17.21%	100.00%
Firm Power Products and Services		479,485	99,670	579,154		82.79%	17.21%	100.00%
TOTALS	4,626,889	4,070,078	168,432	8,865,398	52.19%	45.91%	1.90%	100.00%
				236,757				
			Average Cost of Resources	37.45				

CHAPTER 3: SLICE TRUE-UP ADJUSTMENT CHARGE FORECAST TABLES

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	A	B	C	D	E	F	G	H
1		**TABLE 3.1** **Slice True-Up Adjustment Charge Forecast Prior to Shift in Expenses** **SLICE PRODUCT COSTING AND TRUE-UP TABLE** **($000s)**						
2			**Audited Actual Data**	**FY 2010 forecast**		**FY 2011 forecast**		
3	1	**Operating Expenses**						
4	2	**Power System Generation Resources**						
5	3	**Operating Generation**						
6	4	COLUMBIA GENERATING STATION (WNP-2)		$ 269,200		$ 365,000		
7	5	BUREAU OF RECLAMATION		$ 87,700		$ 98,550		
8	6	CORPS OF ENGINEERS		$ 193,000		$ 197,911		
9	7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 31,889		$ 32,343		
10	8	**Sub-Total**		**$ 581,789**		**$ 693,804**		
11	9	**Operating Generation Settlement Payment**						
12	10	COLVILLE GENERATION SETTLEMENT		$ 21,328		$ 21,754		
13	11	**Sub-Total**		**$ 21,328**		**$ 21,754**		
14	12	**Non-Operating Generation**						
15	13	TROJAN DECOMMISSIONING		$ 2,200		$ 2,300		
16	14	WNP-1&3 DECOMMISSIONING		$ 418		$ 428		
17	15	**Sub-Total**		**$ 2,618**		**$ 2,728**		
18	16	**Contracted Power Purchases**						
19	17	COST OF DSI SERVICE		$ 58,867		$ 58,867		
20	18	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)		$ -		$ -		
21	19	PNCA HEADWATER BENEFITS		$ 2,042		$ 2,620		
22	20	GROSS OTHER POWER PURCHASES (short term - omit)						
23	21	**Sub-Total**		**$ 60,909**		**$ 61,487**		
24	22	**Bookout Adjustment to Power Purchases (omit)**						
25	23	**Augmentation Power Purchases (omit - calculated below)**						
26	24	AUGMENTATION POWER PURCHASES (omit)						
27	25	CONSERVATION AUGMENTATION (omit)						
28	26	**Sub-Total**		**$ -**		**$ -**		
29	27	**Exchanges and Settlements**						
30	28	PUBLIC RESIDENTIAL EXCHANGE		$ 11,974		$ 7,495		
31	29	IOU RESIDENTIAL EXCHANGE		$ 253,883		$ 258,798		
32	30	OTHER SETTLEMENTS		$ -		$ -		
33	31	**Sub-Total**		**$ 265,857**		**$ 266,293**		
34	32	**Renewable Generation**						
35	33	RENEWABLES R&D		$ 4,833		$ 6,092		
36	34	RENEWABLES CONSERVATION RATE CREDIT		$ 4,000		$ 2,500		
37	35	RENEWABLES (excludes expenses from reinvested revenues)		$ 31,715		$ 32,306		
38	36	**Sub-Total**		**$ 40,548**		**$ 40,898**		
39	37	**Generation Conservation**						
40	38	GENERATION CONSERVATION R&D						
41	39	DSM TECHNOLOGIES		$ 1,600		$ 1,600		
42	40	CONSERVATION ACQUISITION		$ 14,000		$ 14,000		
43	41	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000		$ 5,000		
44	42	ENERGY EFFICIENCY DEVELOPMENT		$ 20,500		$ 20,500		
45	43	LEGACY		$ 1,988		$ 1,622		
46	44	MARKET TRANSFORMATION		$ 12,000		$ 12,000		
47	45	**Sub-Total**		**$ 55,088**		**$ 54,722**		
48	46	**Conservation and Renewable Discount (C&RD)**						
49	47	CONSERVATION RATE CREDIT		$ 32,000		$ 32,000		
50	48	CONSERVATION AND RENEWABLE DISCOUNT						
51	49	**Sub-Total**		**$ 32,000**		**$ 32,000**		
52	50	**Power System Generation Sub-Total**		**$ 1,060,137**		**$ 1,173,686**		
53	51	**Power Services Transmission Acquisition and Ancillary Services**						
54	52	**Transmission Acquisition and Ancillary Services**						
55	53	TRANSMISSION & ANCILLARY SERVICES						
56	54	Canadian Entitlement Agreement Transmission Expenses		$ 27,000		$ 27,000		
57	55	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,000		$ 1,000		
58	56	3RD PARTY GTA WHEELING		$ 50,690		$ 51,340		
59	57	3RD PARTY TRANS & ANCILLARY SVCS						
60	58	GENERATION INTEGRATION		$ 6,800		$ 6,800		
61	59	TELEMETERING/EQUIP REPLACEMT		$ 50		$ 50		
62	60	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 85,540**		**$ 86,190**		
63	61							
64	62	**Power Non-Generation Operations**						
65	63	**System Operations**						
66	64	SYSTEM OPERATIONS R&D		$ -		$ -		
67	65	EFFICIENCIES PROGRAM (excludes TMS expenses)		$ -		$ -		
68	66	INFORMATION TECHNOLOGY		$ 6,359		$ 6,324		
69	67	GENERATION PROJECT COORDINATION		$ 7,892		$ 8,118		
70	68	SLICE IMPLEMENTATION (omit - calculated separately)						
71	69	**Sub-Total**		**$ 14,251**		**$ 14,442**		
72	70	**Scheduling**						
73	71	SCHEDULING R&D						
74	72	OPERATIONS SCHEDULING		$ 9,999		$ 10,350		
75	73	OPERATIONS PLANNING		$ 6,207		$ 6,473		
76	74	**Sub-Total**		**$ 16,206**		**$ 16,823**		
77	75	**Marketing and Business Support**						
78	76	SALES & SUPPORT		$ 19,391		$ 19,617		
79	77	Contractual exclusion		$ (5,360)		$ (5,360)		
80	78	Implementation Expense Exclusions - Add back						
81	79	PUBLIC COMMUNICATION & TRIBAL LIAISON						
82	80	STRATEGY, FINANCE & RISK MGMT		$ 17,151		$ 17,632		
83	81	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 3,645		$ 5,320		
84	82	CONSERVATION SUPPORT (EE staff costs)		$ 9,359		$ 9,947		
85	83	**Sub-Total**		**$ 44,186**		**$ 47,156**		
86	84	**Power Non-Generation Operations Sub-Total**		**$ 74,643**		**$ 78,421**		
87	85	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**						
88	86	**BPA Fish and Wildlife (includes F&W Shared Services)**						
89	87	FISH & WILDLIFE		$ 230,000		$ 236,000		
90	88	**Sub-Total**		**$ 230,000**		**$ 236,000**		
91	89	**USF&W Lower Snake Hatcheries**						
92	90	USF&W LOWER SNAKE HATCHERIES		$ 23,600		$ 24,480		
93	91	**Planning Council**						
94	92	PLANNING COUNCIL		$ 9,641		$ 9,838		
95	93	**Environmental Requirements**						
96	94	ENVIRONMENTAL REQUIREMENTS		$ 300		$ 300		
97	95	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 263,541**		**$ 270,618**		
98	96	**General and Administrative/Shared Services**						
99	97	**Additional Post-Retirement Contribution**						
100	98	ADDITIONAL POST-RETIREMENT CONTRIBUTION		$ 15,598		$ 16,071		
101	99	**BPA Internal Support - G&A and Shared Srv. (excludes direct project support)**						
102	100	AGENCY SERVICES G&A		$ 51,877		$ 52,270		
103	101	**Sub-Total BPA Internal Support Services**		**$ 51,877**		**$ 52,270**		

TABLE 3.1
Slice True-Up Adjustment Charge Forecast Prior to Shift in Expenses
SLICE PRODUCT COSTING AND TRUE-UP TABLE
($000s)

	A	B	C	D	E	F	G	H
2			Audited Actual Data	FY 2010 forecast		FY 2011 forecast		
104	102	**Supply Chain - Shared Services**						
105	103	**General and Administrative/Shared Services Sub-Total**		**$ 67,475**		**$ 68,341**		
106	104	**Bad Debt Expense**		$ -		$ -		
107	105	**Other Income, Expenses, Adjustments**		**$ -**		**$ -**		
108	106	**Non-Federal Debt Service**						
109	107	**Energy Northwest Debt Service**						
110	108	COLUMBIA GENERATING STATION DEBT SVC		$ 234,333		$ 227,762		
111	109	WNP-1 DEBT SVC		$ 163,171		$ 165,072		
112	110	WNP-3 DEBT SVC		$ 139,704		$ 164,849		
113	111	EN RETIRED DEBT						
114	112	EN LIBOR INTEREST RATE SWAP						
115	113	**Sub-Total**		**$ 537,208**		**$ 557,683**		
116	114	**Non-EN Debt Service**						
117	115	COWLITZ FALLS DEBT SVC		$ 11,566		$ 11,563		
118	116	N. WASCO DEBT SVC		$ 2,200		$ 2,196		
119	117	TROJAN DEBT SVC		$ -		$ -		
120	118	CONSERVATION DEBT SVC		$ 5,079		$ 4,924		
121	119	**Sub-Total**		**$ 18,845**		**$ 18,683**		
122	120	**Non-Federal Debt Service Sub-Total**		**$ 556,053**		**$ 576,366**		
123	121	**Depreciation (excludes TMS)**		$ 118,616		$ 119,920		
124	122	**Amortization (excludes ConAug amortization)**		$ 65,783		$ 73,654		
125	123	**Total Operating Expenses**		**$ 2,291,788**		**$ 2,447,196**		
126	124							
127	125	**Other Expenses**						
128	126	Net Interest Expense		$ 165,823		$ 171,720		
129	127	LDD		$ 28,303		$ 28,646		
130	128	Irrigation Rate Mitigation Costs		$ 12,036		$ 12,036		
131	129	**Sub-Total**		**$ 206,162**		**$ 212,402**		
132	130	**Total Expenses**		**$ 2,497,950**		**$ 2,659,598**		
133	131							
134	132	**Revenue Credits**						
135	133	Ancillary and Reserve Service Revs. Total		$ 180,452		$ 215,811		
136	134	Downstream Benefits and Pumping Power		$ 8,921		$ 8,921		
137	135	4(h)(10)(c)		$ 88,705		$ 89,975		
138	136	Colville and Spokane Settlements		$ 4,600		$ 4,600		
139	137	FCCF						
140	138	Energy Efficiency Revenues		$ 20,500		$ 20,500		
141	139	Miscellaneous		$ 3,420		$ 3,420		
142	140	Ad Hoc revenue credit adjustment		$ (34,620)		$ (34,620)		
143	141	**Total Revenue Credits**		**$ 271,978**		**$ 308,607**		
144	142	**Augmentation Costs**						
145	143	**Forecasted Gross Augmentation Costs**						Net cost before shift
146	144	Augmentation cost		$ 176,580		$ 304,818		
147	145	Minus revenues 382.3 aMW, 606.6 aMW		$ 98,560		$ 156,386		
148	146	**Net Cost of Augmentation**		**$ 78,020**		**$ 148,432**		
149	147	Shift in Net Cost of Augmentation						
150	148	**Net Cost of Augmentation after shift**						
151	149	**Minimum Required Net Revenue calculation**						Amortization paymt
152	150	Principal Payment of Fed Debt for Power		$ 217,264		$ 211,888		before shift
153	151	Irrigation assistance		$ -		$ -		
154	152	Depreciation		$ 118,616		$ 119,920		
155	153	Amortization		$ 79,118		$ 86,989		
156	154	Capitalization Adjustment		$ (45,937)		$ (45,937)		
157	155	Bond Premium Amortization		$ 185		$ 185		
158	156	Principal Payment of Fed Debt exceeds non cash expenses		$ 65,282		$ 50,731		
159	157	Minimum Required Net Revenues		**$ 65,282**		**$ 50,731**		
160	158							**2-Year Total Rev Reqt**
161	159	Annual Slice Revenue Requirement (Amounts for each FY)		**$ 2,369,274**		**$ 2,550,154**		**$ 4,919,429**
162	160							
163	161	SLICE TRUE-UP ADJUSTMENT CALCULATION				$ 180,880		
164	162							
165	163	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case		**$ 2,459,714**				
166	164	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)		$ (90,440)		$ 90,440		True-Up before
167	165	AMOUNT BILLED (22.6278 percent)		$ (20,465)		$ 20,465		shifts in expenses
168	166	Slice Implementation Expenses (not incl. in base rate)		$ 2,790		$ 2,870		
169	167	TRUE UP ADJUSTMENT		**$ (17,675)**	**FY 2010**	**$ 23,335**	**FY 2011**	
170	168				**True-Up**		**True-Up**	
171	169							
172	170	**SLICE RATE CALCULATION ($)**						
173	171	**Monthly Slice Revenue Requirement (2-Year total divided by 24 months)**						**$ 204,976,202**
174	172	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**						**$ 2,049,762**
175	173							
176	174	**ANNUAL BASE SLICE REVENUES**						**$ 556,579,261**
177	175	**Annual Slice Implementation Expenses**						**$ 2,830,000**
178	176	**TOTAL ANNUAL SLICE REVENUES**						**$ 559,409,261**
179								

TABLE 3.2
Slice True-Up Adjustment Charge Forecast After the Shift in Expenses
SLICE PRODUCT COSTING AND TRUE-UP TABLE
($000s)

A	B	C Audited Actual Data	D FY 2010 forecast	F FY 2011 forecast
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)		$ 269,200	$ 365,000
5	BUREAU OF RECLAMATION		$ 87,700	$ 98,550
6	CORPS OF ENGINEERS		$ 193,000	$ 197,911
7	LONG-TERM CONTRACT GENERATING PROJECTS		$ 31,889	$ 32,343
8	**Sub-Total**		**$ 581,789**	**$ 693,804**
9	**Operating Generation Settlement Payment**			
10	COLVILLE GENERATION SETTLEMENT		$ 21,328	$ 21,754
11	**Sub-Total**		**$ 21,328**	**$ 21,754**
12	**Non-Operating Generation**			
13	TROJAN DECOMMISSIONING		$ 2,200	$ 2,300
14	WNP-1&3 DECOMMISSIONING		$ 418	$ 428
15	**Sub-Total**		**$ 2,618**	**$ 2,728**
16	**Contracted Power Purchases**			
17	COST OF DSI SERVICE		$ 58,867	$ 58,867
18	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)		$ -	$ -
19	PNCA HEADWATER BENEFITS		$ 2,042	$ 2,620
20	GROSS OTHER POWER PURCHASES (short term - omit)			
21	**Sub-Total**		**$ 60,909**	**$ 61,487**
22	**Bookout Adjustment to Power Purchases (omit)**			
23	**Augmentation Power Purchases (omit - calculated below)**			
24	AUGMENTATION POWER PURCHASES (omit)			
25	CONSERVATION AUGMENTATION (omit)			
26	**Sub-Total**		**$ -**	**$ -**
27	**Exchanges and Settlements**			
28	PUBLIC RESIDENTIAL EXCHANGE		$ 11,974	$ 7,495
29	IOU RESIDENTIAL EXCHANGE		$ 253,883	$ 258,798
30	OTHER SETTLEMENTS		$ -	$ -
31	**Sub-Total**		**$ 265,857**	**$ 266,293**
32	**Renewable Generation**			
33	RENEWABLES R&D		$ 4,833	$ 6,092
34	RENEWABLES CONSERVATION RATE CREDIT		$ 4,000	$ 2,500
35	RENEWABLES (excludes expenses from reinvested revenues)		$ 31,715	$ 32,306
36	**Sub-Total**		**$ 40,548**	**$ 40,898**
37	**Generation Conservation**			
38	GENERATION CONSERVATION R&D			
39	DSM TECHNOLOGIES		$ 1,600	$ 1,600
40	CONSERVATION ACQUISITION		$ 14,000	$ 14,000
41	LOW INCOME WEATHERIZATION & TRIBAL		$ 5,000	$ 5,000
42	ENERGY EFFICIENCY DEVELOPMENT		$ 20,500	$ 20,500
43	LEGACY		$ 1,988	$ 1,622
44	MARKET TRANSFORMATION		$ 12,000	$ 12,000
45	**Sub-Total**		**$ 55,088**	**$ 54,722**
46	**Conservation and Renewable Discount (C&RD)**			
47	CONSERVATION RATE CREDIT		$ 32,000	$ 32,000
48	CONSERVATION AND RENEWABLE DISCOUNT			
49	**Sub-Total**		**$ 32,000**	**$ 32,000**
50	**Power System Generation Sub-Total**		**$ 1,060,137**	**$ 1,173,686**
51	**Power Services Transmission Acquisition and Ancillary Services**			
52	**Transmission Acquisition and Ancillary Services**			
53	TRANSMISSION & ANCILLARY SERVICES			
54	Canadian Entitlement Agreement Transmission Expenses		$ 27,000	$ 27,000
55	PNCA & NTS Transmission and System Obligaton Expenses		$ 1,000	$ 1,000
56	3RD PARTY GTA WHEELING		$ 50,690	$ 51,340
57	3RD PARTY TRANS & ANCILLARY SVCS			
58	GENERATION INTEGRATION		$ 6,800	$ 6,800
59	TELEMETERING/EQUIP REPLACEMT		$ 50	$ 50
60	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**		**$ 85,540**	**$ 86,190**
61				
62	**Power Non-Generation Operations**			
63	**System Operations**			
64	SYSTEM OPERATIONS R&D		$ -	$ -
65	EFFICIENCIES PROGRAM (excludes TMS expenses)		$ -	$ -
66	INFORMATION TECHNOLOGY		$ 6,359	$ 6,324
67	GENERATION PROJECT COORDINATION		$ 7,892	$ 8,118
68	SLICE IMPLEMENTATION (omit - calculated separately)			
69	**Sub-Total**		**$ 14,251**	**$ 14,442**
70	**Scheduling**			
71	SCHEDULING R&D			
72	OPERATIONS SCHEDULING		$ 9,999	$ 10,350
73	OPERATIONS PLANNING		$ 6,207	$ 6,473
74	**Sub-Total**		**$ 16,206**	**$ 16,823**
75	**Marketing and Business Support**			
76	SALES & SUPPORT		$ 19,391	$ 19,617
77	Contractual exclusion		$ (5,360)	$ (5,360)
78	Implementation Expense Exclusions - Add back			
79	PUBLIC COMMUNICATION & TRIBAL LIAISON			
80	STRATEGY, FINANCE & RISK MGMT		$ 17,151	$ 17,632
81	EXECUTIVE AND ADMINISTRATIVE SERVICES		$ 3,645	$ 5,320
82	CONSERVATION SUPPORT (EE staff costs)		$ 9,359	$ 9,947
83	**Sub-Total**		**$ 44,186**	**$ 47,156**
84	**Power Non-Generation Operations Sub-Total**		**$ 74,643**	**$ 78,421**
85	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
86	**BPA Fish and Wildlife (includes F&W Shared Services)**			
87	FISH & WILDLIFE		$ 230,000	$ 236,000
88	**Sub-Total**		**$ 230,000**	**$ 236,000**
89	**USF&W Lower Snake Hatcheries**			
90	USF&W LOWER SNAKE HATCHERIES		$ 23,600	$ 24,480
91	**Planning Council**			
92	PLANNING COUNCIL		$ 9,641	$ 9,838
93	**Environmental Requirements**			
94	ENVIRONMENTAL REQUIREMENTS		$ 300	$ 300

	A	B	C	D	E	F	G	H
1		**TABLE 3.2** **Slice True-Up Adjustment Charge Forecast After the Shift in Expenses** **SLICE PRODUCT COSTING AND TRUE-UP TABLE** **($000s)**						
2			**Audited Actual Data**	**FY 2010 forecast**		**FY 2011 forecast**		
97	95	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**$ 263,541**		**$ 270,618**		
98	96	**General and Administrative/Shared Services**						
99	97	**Additional Post-Retirement Contribution**						
100	98	ADDITIONAL POST-RETIREMENT CONTRIBUTION		$ 15,598		$ 16,071		
101	99	**BPA Internal Support - G&A and Shared Srv. (excludes direct project support)**						
102	100	AGENCY SERVICES G&A		$ 51,877		$ 52,270		
103	101	**Sub-Total BPA Internal Support Services**		**$ 51,877**		**$ 52,270**		
104	102	**Supply Chain - Shared Services**						
105	103	**General and Administrative/Shared Services Sub-Total**		**$ 67,475**		**$ 68,341**		
106	104	**Bad Debt Expense**		$ -		$ -		
107	105	**Other Income, Expenses, Adjustments**		**$ -**		**$ -**		
108	106	**Non-Federal Debt Service**						
109	107	**Energy Northwest Debt Service**						
110	108	COLUMBIA GENERATING STATION DEBT SVC		$ 234,333		$ 227,762		
111	109	WNP-1 DEBT SVC		$ 163,171		$ 165,072		
112	110	WNP-3 DEBT SVC		$ 139,704		$ 164,849		
113	111	EN RETIRED DEBT						
114	112	EN LIBOR INTEREST RATE SWAP						
115	113	**Sub-Total**		**$ 537,208**		**$ 557,683**		
116	114	**Non-EN Debt Service**						
117	115	COWLITZ FALLS DEBT SVC		$ 11,566		$ 11,563		
118	116	N. WASCO DEBT SVC		$ 2,200		$ 2,196		
119	117	TROJAN DEBT SVC		$ -		$ -		
120	118	CONSERVATION DEBT SVC		$ 5,079		$ 4,924		
121	119	**Sub-Total**		**$ 18,845**		**$ 18,683**		
122	120	**Non-Federal Debt Service Sub-Total**		**$ 556,053**		**$ 576,366**		
123	121	**Depreciation (excludes TMS)**		$ 118,616		$ 119,920		
124	122	**Amortization (excludes ConAug amortization)**		$ 65,783		$ 73,654		
125	123	**Total Operating Expenses**		**$ 2,291,788**		**$ 2,447,196**		
126	124							
127	125	**Other Expenses**						
128	126	Net Interest Expense		$ 165,823		$ 171,720		
129	127	LDD		$ 28,303		$ 28,646		
130	128	Irrigation Rate Mitigation Costs		$ 12,036		$ 12,036		
131	129	**Sub-Total**		**$ 206,162**		**$ 212,402**		
132	130	**Total Expenses**		**$ 2,497,950**		**$ 2,659,598**		
133	131							
134	132	**Revenue Credits**						
135	133	Ancillary and Reserve Service Revs. Total		$ 180,452		$ 215,811		
136	134	Downstream Benefits and Pumping Power		$ 8,921		$ 8,921		
137	135	4(h)(10)(c)		$ 88,705		$ 89,975		
138	136	Colville and Spokane Settlements		$ 4,600		$ 4,600		
139	137	FCCF						
140	138	Energy Efficiency Revenues		$ 20,500		$ 20,500		
141	139	Miscellaneous		$ 3,420		$ 3,420		
142	140	Ad Hoc revenue credit adjustment		$ (34,620)		$ (34,620)		
143	141	**Total Revenue Credits**		**$ 271,978**		**$ 308,607**		
144	142	**Augmentation Costs**						
145	143	**Forecasted Gross Augmentation Costs**						Net cost before shift
146	144	Augmentation cost		$ 176,580		$ 304,818		
147	145	Minus revenues 382.3 aMW, 606.6 aMW		$ 98,560		$ 156,386		
148	146	**Net Cost of Augmentation**		**$ 78,020**		**$ 148,432**		
149	147	Shift in Net Cost of Augmentation		$ 53,124		$ (53,124)		
150	148	**Net Cost of Augmentation after shift**		**$ 131,144**		**$ 95,308**		Net cost after shift
151	149	**Minimum Required Net Revenue calculation**						
152	150	Principal Payment of Fed Debt for Power		$ 267,264		$ 161,888		Amortization paymt
153	151	Irrigation assistance		$ -		$ -		after shift
154	152	Depreciation		$ 118,616		$ 119,920		
155	153	Amortization		$ 79,118		$ 86,989		
156	154	Capitalization Adjustment		$ (45,937)		$ (45,937)		
157	155	Bond Premium Amortization		$ 185		$ 185		
158	156	Principal Payment of Fed Debt exceeds non cash expenses		$ 115,282		$ 731		
159	157	Minimum Required Net Revenues		**$ 115,282**		**$ 731**		
160	158							**2-Year Total Rev Reqt**
161	159	Annual Slice Revenue Requirement (Amounts for each FY)		**$ 2,472,398**		**$ 2,447,030**		**$ 4,919,429**
162	160							
163	161	SLICE TRUE-UP ADJUSTMENT CALCULATION				$ (25,368)		
164	162							
165	163	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case		**$ 2,459,714**				
166	164	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)		$ 12,684		$ (12,684)		
167	165	AMOUNT BILLED (22.6278 percent)		$ 2,870		$ (2,870)		
168	166	Slice Implementation Expenses (not incl. in base rate)		$ 2,790		$ 2,870		
169	167	TRUE UP ADJUSTMENT		**$ 5,660**	**FY 2010**	**$ (0)**	**FY 2011**	
170	168				**True-Up**		**True-Up**	
171	169							
172	170	**SLICE RATE CALCULATION ($)**						
173	171	**Monthly Slice Revenue Requirement (2-Year total divided by 24 months)**						**$ 204,976,202**
174	172	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**						**$ 2,049,762**
175	173							
176	174	**ANNUAL BASE SLICE REVENUES**						**$ 556,579,261**
177	175	**Annual Slice Implementation Expenses**						**$ 2,830,000**
178	176	**TOTAL ANNUAL SLICE REVENUES**						**$ 559,409,261**
179								

CHAPTER 4: REVENUE FORECAST

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Table 4.5 4h10C Credits

	A	B	C	D	E	F	G	H
2				**4h10C credits ($Million)**				
3								
4								
5	**Fiscal Year**	**Purch Cost**	**BPA Exp.**	**BPA Cap.**	**Total**	**Credit @ 22.3%**		
6	**FY 2010**	96.0	231.8	70.0	397.8	**88.7**		
7	**FY 2011**	105.7	237.8	60.0	403.5	**90.0**		

Table 4.6.1 Summary of Revenues at Current Rates

	A	B	C	D	E	F	G
2		FY 2009		FY 2010		FY 2011	
3	**Revenues**	**($000)**	**aMW**	**($000)**	**aMW**	**($000)**	**aMW**
4	**PF Preference**	$1,170,394	5,353	$1,260,545	5,436	$1,276,926	5,508
5	**PF Slice**	$503,854	2,109	$503,840	2,157	$503,843	2,132
6	**Pre-sub/Hungry Horse**	$39,736	231	$37,313	203	$34,915	206
7	**Irrigation Mitigation**	$20,220	196	$20,220	196	$20,206	196
8	**Slice true-up**	$6,942	0	$5,660	0	$0	0
9	**Industrial Power**	$0	0	$3,875	17	$3,875	17
10	**Long-Term Obligations**	$90,689	625	$99,495	655	$89,796	609
11	**Generation Inputs**	$80,488	0	$155,290	0	$155,290	0
12	**4h10C credits**	$84,851	0	$88,705	0	$89,975	0
13	**Colville credits**	$4,600	0	$4,600	0	$4,600	0
14	**EE and misc revenues**	$30,125	0	$30,865	0	$30,865	0
15	**DSB/IPP/Reserve Energy**	$9,072	159	$8,921	159	$8,921	159
16	**Secondary Sales**	$353,147	1,083	$599,737	1,630	$699,967	1,663
17	**Bookouts**	($13,910)	-32	$0	0	$0	0
18	**Ad hoc Gen Input adjustment**	$0	0	($34,620)	0	($34,620)	0
19	**Total Revenue**	$2,380,207	9,723	$2,784,447	10,453	$2,884,560	10,491
20							
21	**Purchases**						
22	**Augmentation Purchases**	$3,126	13	$176,580	382	$304,818	607
23	**Secondary Purchases**	$90,252	79	$66,353	144	$53,121	109
24							

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1							Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2009**									
4																
5																
6														**Fiscal Year 2009**		
7	WESTERN HUB	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8		$5,898	$8,097	$9,437	$7,968	$6,787	$6,257	$5,318	$4,108	$2,487	$4,454	$5,058	$5,840	$71,709		
9	**West Hub PF Billing Determinants**	$13,494	$16,474	$19,303	$16,726	$15,164	$13,743	$11,713	$8,832	$7,799	$9,411	$11,520	$11,305	$155,485		
10	**PF Full Service**	$2,670	$3,274	$3,698	$3,312	$3,273	$2,697	$2,262	$1,458	$1,285	$1,611	$1,830	$1,869	$29,239		
11	LLH Energy Flat	275,595	356,381	395,699	399,216	336,634	326,384	301,624	289,916	252,472	266,250	254,797	263,424	3,718,392	424	3718
12	HLH Energy Flat	461,962	528,870	593,758	606,019	537,921	525,558	477,297	430,813	420,450	411,867	430,484	409,319	5,834,318	666	5834
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat Revenue = 11*13/1(	$5,343	$8,097	$9,437	$7,968	$6,787	$6,257	$5,318	$4,108	$2,487	$4,454	$5,058	$5,840	$71,154		
16	HLH Energy Revenue Flat Revenue= 12*14/1(	$12,694	$16,474	$19,303	$16,726	$15,164	$13,743	$11,713	$8,832	$7,799	$9,411	$11,520	$11,305	$154,685		
17	Demand	1,398	1,605	1,728	1,820	1,769	1,568	1,396	1,088	1,045	1,074	1,040	1,027	16,558		
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue = 23*24	$2,563	$3,274	$3,698	$3,312	$3,273	$2,697	$2,262	$1,458	$1,285	$1,611	$1,830	$1,869	$29,132		
20	Load Variance	750,216	940,845	1,048,618	1,063,301	926,893	909,632	836,154	782,813	732,274	737,461	743,680	725,315	10,197,202	1164	10197
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance Revenue = 26*27/1000	$315	$433	$482	$489	$426	$418	$385	$360	$337	$339	$342	$334	$4,661		
23	Low Density Discount Percent =30/(15+16+21	-1.66%	-2.32%	-2.35%	-2.39%	-2.38%	-2.38%	-2.38%	-2.44%	-2.40%	-2.28%	-2.26%	-2.26%			
24	Low Density Discount	-$348	-$657	-$775	-$682	-$610	-$550	-$468	-$360	-$286	-$361	-$425	-$438	-$5,960		
25	LBCRAC True-up/Lookback Adjust	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$1,009	-$12,103		
26	PF Other Energy	0														
27	PF Other revenues	$4												$4		
28		$6,680	$8,038	$8,836	$7,256	$6,526	$6,270	$5,250	$5,048	$2,636	$4,855	$5,766	$6,458	$73,621		
29	**PF Partial Service**	$14,538	$18,486	$21,388	$18,199	$16,958	$15,162	$13,621	$11,657	$9,097	$11,913	$14,511	$14,291	$179,817		
30	LLH Energy Flat	312,148	353,776	370,485	363,536	323,714	327,080	297,780	356,279	267,650	290,224	290,497	291,308	3,844,477	439	3,844
31	HLH Energy Flat	497,690	593,452	657,875	659,372	601,550	579,795	555,036	568,611	490,382	521,350	542,248	517,406	6,784,767	775	6,785
32	LLH Energy Revenue Flat (40*13)/1000	$6,681	$8,038	$8,836	$7,256	$6,526	$6,270	$5,250	$5,048	$2,636	$4,855	$5,766	$6,458	$73,622		
33	HLH Energy Revenue Flat (41*14)/1000	$14,535	$18,486	$21,388	$18,199	$16,958	$15,162	$13,621	$11,657	$9,097	$11,913	$14,511	$14,291	$179,815		
34	GSP Demand	1,454	1,569	1,551	1,666	1,653	1,468	1,425	1,359	1,168	1,252	1,262	1,265	17,092		
35	Demand Revenue (44*24)	$2,777	$3,201	$3,320	$3,033	$3,058	$2,525	$2,308	$1,822	$1,437	$1,878	$2,221	$2,303	$29,882		
36	Load Variance	1,038,945	1,179,044	1,290,219	1,275,778	1,146,224	1,144,954	1,087,995	1,052,352	1,007,251	1,042,228	1,053,565	1,021,789	13,340,344	1523	13340
37	Load Variance Revenue (45*27)/1000	$478	$542	$594	$587	$527	$527	$500	$484	$463	$479	$485	$470	$6,137		
38	LBCRAC True-up/Lookback Adjust	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$1,134	-$13,608		
39	PF Other Energy	0														
40	PF Other revenues	$0												$0		
41		$8,406	$12,516	$14,361	$12,163	$10,799	$10,787	$7,105	$5,151	$2,874	$5,982	$7,756	$9,931	$107,830		
42	**PF Block Service**	$16,430	$19,553	$24,827	$21,331	$20,133	$18,720	$13,534	$8,416	$7,202	$9,998	$12,887	$15,465	$188,495		
43	LLH Energy Flat	392,808	550,868	602,122	609,360	535,655	562,702	403,016	363,494	291,791	357,555	390,748	447,947	5,508,066	629	5,508
44	HLH Energy Flat	562,464	627,695	763,666	772,847	714,207	715,854	551,495	410,513	388,255	437,536	481,595	559,934	6,986,061	797	6,986
45	LLH Energy Revenue Flat (55*13)/1000	$8,406	$12,516	$14,361	$12,163	$10,799	$10,787	$7,105	$5,151	$2,874	$5,982	$7,756	$9,931	$107,830		
46	LLH Energy Revenue Stepped (56*19)/1000													$0		
47	HLH Energy Revenue Flat (56*14)/1000	$16,430	$19,553	$24,827	$21,331	$20,133	$18,720	$13,534	$8,416	$7,202	$9,998	$12,887	$15,465	$188,495		
48	HLH Energy Revenue Stepped (57*20)/1000													$0		
49	GSP Demand	1,408	1,635	1,836	1,858	1,860	1,721	1,326	1,137	1,088	1,225	1,308	1,400	17,802		
50	Demand Revenue (62*24)	$2,689	$3,335	$3,928	$3,381	$3,441	$2,960	$2,148	$1,523	$1,338	$1,838	$2,303	$2,548	$31,432		
51	LBCRAC True-up/Lookback Adjust	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$1,310	-$15,718		
52	PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53	Low Density Discount Percent = 70/(59+60+61	-0.89%	-0.81%	-0.83%	-0.84%	-0.81%	-0.75%	-1.00%	-0.94%	-0.87%	-0.78%	-0.71%	-0.95%			
54	Low-Density Discount	-$246	-$288	-$358	-$310	-$278	-$244	-$228	-$143	-$99	-$140	-$162	-$266	-$2,761		
55	PF Other Energy													0		
56	PF Block Other Revenues													$0		
57									$1,334	$1,603	$2,428	$2,494		$7,859		
58	**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,975	39,179	0	152,052	17	152
59	**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	45,493	65,398	73,313	64,136	0	248,340	28	248
60	**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$710	$721	$1,383	$1,568	$0	$4,382		
61														$0		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2009**															
4																
5																
6														**Fiscal Year 2009**		
7	WESTERN HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
62																
63	**TAC LLH**													0	-	-
64	**TAC HLH**													0	-	-
65	**TAC Demand**													0		
66	**TAC Revenue**													$0		
67																
68	PF SLICE	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$415,917		
69	Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1726	
70	Slice rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
71	Slice Charges ($000) 90*91	$34,660	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$415,948		
72	Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	LBCRAC True-up/Lookback Adjust	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$1,092	-$13,098		
74	LDD Percentage	-1.08%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75	Low-Density Discount	-373	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$4,655		
76	Slice Other	$0														
77	**West Hub FPS (Pre-Subscription) Sales**															
78	LLH Energy Full Service	6,372	7,142	6,956	6,955	6,140	7,558	10,251	16,811	18,795	23,456	22,001	17,162	149,599	17	150
79	LLH Energy Revenue	$137	$161	$163	$142	$125	$137	$119	$115	$79	$124	$141	$150	$1,594		
80	HLH Energy Full Service	8,599	8,139	8,821	8,821	8,187	9,656	14,237	20,043	26,084	30,007	28,504	21,625	192,723	22	193
81	HLH Energy Revenue	$239	$239	$268	$234	$220	$224	$212	$176	$170	$200	$228	$225	$2,634		
82	GSP Demand	22	21	21	21	21	25	48	59	66	70	69	61	504		
83	Demand Revenue	$30	$35	$36	$31	$31	$29	$28	$23	$21	$26	$30	$31	$351		
84	Load Variance	15,737	15,281	15,777	15,776	14,327	17,214	24,488	36,854	44,879	53,463	50,505	38,787	343088	39	343
85	Load Variance Revenue	$7	$7	$7	$7	$7	$8	$11	$17	$21	$25	$23	$18	$158		
86	Low-Density Discount													$0		
87	LT SURPLUS FB CRAC															
88	Netrwork Wind Integration Service													$0		
89	Other Pre-Subscription revenues	$10												$10		
90																
91	Public Agency Residential Exchange															
92	Monthly Energy Flat													0	-	-
93	Monthly Energy Flat Rate	42.32	50.89	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94	Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95	GSP Demand													0		
96	GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97	Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98	**Total**	$102,489	$123,175	$139,245	$123,596	$116,316	$109,398	$93,546	$79,125	$67,312	$83,745	$95,812	$100,264	$1,276,447		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1								Revenues at Current Rates								
2								Revenue ($ Thousands)								
3								**Fiscal Year 2010**								
4																
5																
6														**Fiscal Year 2010**		
7	WESTERN HUB	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8		$5,983	$8,164	$9,522	$8,014	$6,754	$6,214	$5,323	$4,105	$2,486	$4,645	$5,047	$5,839	$72,096		
9	**West Hub PF Billing Determinants**	$13,596	$16,680	$19,518	$16,688	$15,154	$13,854	$11,760	$8,870	$7,831	$9,146	$11,575	$11,362	$156,034		
10	**PF Full Service**	$2,982	$3,478	$3,916	$3,478	$3,435	$2,850	$2,404	$1,570	$1,389	$1,739	$1,980	$2,020	$31,241		
11	LLH Energy Flat	279,562	359,317	399,260	401,505	335,036	324,157	301,947	289,693	252,349	277,629	254,261	263,385	3,738,101	427	3738
12	HLH Energy Flat	465,445	535,465	600,384	604,638	537,578	529,803	479,230	432,702	422,132	400,246	432,536	411,352	5,851,511	668	5852
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat Revenue = 11*13/1(	$5,939	$8,113	$9,470	$7,969	$6,716	$6,175	$5,288	$4,073	$2,466	$4,609	$5,004	$5,792	$71,612		
16	HLH Energy Revenue Flat Revenue= 12*14/1(	$13,512	$16,600	$19,429	$16,615	$15,083	$13,780	$11,693	$8,816	$7,779	$9,083	$11,501	$11,288	$155,180		
17	Demand	1,561	1,705	1,830	1,911	1,857	1,657	1,484	1,172	1,129	1,159	1,125	1,110	17,700		
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue = 23*24	$2,981	$3,478	$3,915	$3,479	$3,436	$2,850	$2,404	$1,571	$1,389	$1,739	$1,980	$2,020	$31,243		
20	Load Variance	816,107	965,561	1,074,418	1,079,882	939,095	927,201	853,616	800,138	748,975	752,874	760,820	742,444	10,461,131	1194	10461
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance Revenue = 26*27/1000	$375	$444	$494	$497	$432	$427	$393	$368	$345	$346	$350	$342	$4,812		
23	Low Density Discount Percent =30/(15+16+21															
24	Low Density Discount	-$529	-$676	-$796	-$698	-$626	-$564	-$480	-$371	-$295	-$370	-$438	-$452	-$6,294		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy															
27	PF Other revenues													$0		
28		$6,316	$8,260	$9,075	$7,730	$6,717	$6,207	$5,383	$5,157	$2,709	$4,930	$5,916	$6,623	$75,026		
29	**PF Partial Service**	$16,339	$19,035	$22,018	$18,355	$17,472	$15,959	$13,971	$11,926	$9,353	$12,284	$14,880	$14,659	$186,251		
30	LLH Energy Flat	295,151	363,573	380,516	387,296	333,208	323,768	305,359	363,973	275,065	294,708	298,012	298,723	3,919,352	447	3,919
31	HLH Energy Flat	559,373	611,063	677,282	665,044	619,799	610,276	569,312	581,732	504,222	537,595	556,039	530,747	7,022,484	802	7,022
32	LLH Energy Revenue Flat (40*13)/1000	$6,316	$8,260	$9,075	$7,730	$6,717	$6,207	$5,383	$5,157	$2,709	$4,930	$5,916	$6,623	$75,026		
33	HLH Energy Revenue Flat (41*14)/1000	$16,339	$19,035	$22,018	$18,355	$17,472	$15,959	$13,971	$11,925	$9,353	$12,284	$14,880	$14,659	$186,251		
34	GSP Demand	1,426	1,613	1,594	1,695	1,696	1,522	1,460	1,393	1,202	1,300	1,297	1,300	17,498		
35	Demand Revenue (44*24)	$2,724	$3,291	$3,412	$3,085	$3,137	$2,618	$2,366	$1,866	$1,479	$1,950	$2,283	$2,366	$30,577		
36	Load Variance	1,091,374	1,199,153	1,311,354	1,296,845	1,166,316	1,164,957	1,103,375	1,067,278	1,022,863	1,056,823	1,068,637	1,036,552	13,585,527	1551	13586
37	Load Variance Revenue (45*27)/1000	$502	$552	$603	$597	$537	$536	$508	$491	$471	$486	$492	$477	$6,249		
38	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	PF Other Energy															
40	PF Other revenues													$0		
41		$8,910	$12,516	$14,361	$12,755	$10,799	$10,257	$7,105	$5,151	$2,874	$5,982	$7,756	$9,931	$108,396		
42	**PF Block Service**	$16,839	$19,553	$24,827	$20,508	$20,133	$19,436	$13,534	$8,416	$7,202	$9,998	$12,887	$15,465	$188,798		
43	LLH Energy Flat	416,347	550,868	602,122	639,015	535,655	535,076	403,016	363,494	291,791	357,555	390,742	447,947	5,533,628	632	5,534
44	HLH Energy Flat	576,480	627,695	763,666	743,040	714,207	743,257	551,495	410,513	388,255	437,536	481,595	559,934	6,997,673	799	6,998
45	LLH Energy Revenue Flat (55*13)/1000	$8,910	$12,516	$14,361	$12,755	$10,799	$10,257	$7,105	$5,151	$2,874	$5,982	$7,756	$9,931	$108,396		
46	LLH Energy Revenue Stepped (56*19)/1000													$0		
47	HLH Energy Revenue Flat (56*14)/1000	$16,839	$19,553	$24,827	$20,508	$20,133	$19,436	$13,534	$8,416	$7,202	$9,998	$12,887	$15,465	$188,798		
48	HLH Energy Revenue Stepped (57*20)/1000													$0		
49	GSP Demand	1,334	1,635	1,836	1,858	1,860	1,721	1,326	1,137	1,088	1,225	1,308	1,400	17,728		
50	Demand Revenue (62*24)	$2,549	$3,335	$3,928	$3,381	$3,441	$2,959	$2,148	$1,523	$1,338	$1,838	$2,303	$2,548	$31,291		
51	LBCRAC True-up/Lookback Adjust													$0		
52	PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53	Low Density Discount Percent = 70/(59+60+61	-0.89%	-0.81%	-0.83%	-0.84%	-0.81%	-0.75%	-1.00%	-0.94%	-0.87%	-0.78%	-0.71%	-0.95%			
54	Low-Density Discount	-$252	-$288	-$358	-$308	-$278	-$245	-$228	-$143	-$99	-$140	-$162	-$266	-$2,767		
55	PF Other Energy													0		
56	PF Block Other Revenues															
57									$1,334	$1,603	$2,428	$2,494		$7,858		
58	**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,975	39,179	0	152,052	17	152
59	**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	45,477	65,398	73,313	64,132	0	248,320	28	248
60	**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$710	$721	$1,383	$1,568	$0	$4,382		
61														$0		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														**Fiscal Year 2010**		
7	WESTERN HUB	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total	aMW	GWh
62																
63	**TAC LLH**													0	-	-
64	**TAC HLH**													0	-	-
65	**TAC Demand**													0		
66	**TAC Revenue**													$0		
67																
68	PF SLICE	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$415,917		
69	Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1765	
70	Slice rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
71	Slice Charges ($000) 90*91	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$415,951		
72	Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	LBCRAC True-up/Lookback Adjust													$0		
74	LDD Percentage	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75	Low-Density Discount	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$4,671		
76	Slice Other															
77	**West Hub FPS (Pre-Subscription) Sales**															
78	LLH Energy Full Service	1,248	1,348	1,312	1,376	1,152	1,244	1,216	1,376	1,216	1,312	1,312	1,280	15,392	2	15
79	LLH Energy Revenue	$26	$28	$27	$29	$24	$26	$25	$29	$25	$27	$27	$27	$320		
80	HLH Energy Full Service	1,728	1,536	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,664	1,664	1,600	19,648	2	20
81	HLH Energy Revenue	$36	$32	$35	$33	$32	$36	$35	$33	$35	$35	$35	$33	$408		
82	GSP Demand	4	4	4	4	4	4	4	4	4	4	4	4	48		
83	Demand Revenue	$32	$35	$36	$31	$31	$29	$28	$23	$21	$26	$30	$31	$353		
84	Load Variance	2,976	2,884	2,976	2,976	2,688	2,972	2,880	2,976	2,880	2,976	2,976	2,880	35040	4	35
85	Load Variance Revenue	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$16		
86	Low-Density Discount													$0		
87	LT SURPLUS FB CRAC															
88	Netrwork Wind Integration Service													$0		
89	Other Pre-Subscription revenues													$0		
90																
91	Public Agency Residential Exchange															
92	Monthly Energy Flat													0	-	-
93	Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94	Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95	GSP Demand													0		
96	GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97	Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98	**Total**	$110,574	$128,582	$144,753	$128,331	$121,361	$114,759	$98,445	$83,913	$72,087	$88,481	$100,685	$105,159	$1,297,131		

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	WESTERN HUB	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8		$6,015	$8,123	$9,534	$8,038	$6,823	$6,223	$5,330	$4,101	$2,489	$4,476	$5,008	$5,843	$72,003		
9	**West Hub PF Billing Determinants**	$13,598	$16,851	$19,595	$16,790	$15,328	$13,909	$11,803	$8,906	$7,871	$9,451	$11,671	$11,418	$157,190		
10	**PF Full Service**	$3,031	$3,533	$3,974	$3,525	$3,485	$2,886	$2,440	$1,599	$1,415	$1,773	$2,019	$2,057	$31,736		
11	LLH Energy Flat	281,088	357,506	399,739	402,718	338,453	324,639	302,309	289,440	252,723	267,555	252,278	263,534	3,731,982	426	3732
12	HLH Energy Flat	465,526	540,957	602,741	608,336	543,753	531,908	480,950	434,442	424,298	413,608	436,118	413,384	5,896,021	673	5896
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat Revenue = 11*13/1(	$5,940	$8,044	$9,449	$7,964	$6,761	$6,159	$5,272	$4,049	$2,457	$4,414	$4,941	$5,766	$71,217		
16	HLH Energy Revenue Flat Revenue= 12*14/1(	$13,467	$16,716	$19,449	$16,671	$15,212	$13,788	$11,692	$8,818	$7,787	$9,352	$11,546	$11,298	$155,798		
17	Demand	1,587	1,732	1,857	1,937	1,884	1,678	1,506	1,193	1,150	1,182	1,147	1,130	17,983		
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue = 23*24	$3,031	$3,533	$3,974	$3,525	$3,485	$2,886	$2,440	$1,599	$1,415	$1,773	$2,019	$2,057	$31,736		
20	Load Variance	833,329	984,397	1,092,895	1,100,436	962,825	945,415	870,831	817,277	766,655	771,772	778,069	759,780	10,683,681	1220	10684
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance Revenue = 26*27/1000	$383	$453	$503	$506	$443	$435	$401	$376	$353	$355	$358	$349	$4,914		
23	Low Density Discount Percent =30/(15+16+21															
24	Low Density Discount	-$544	-$693	-$814	-$711	-$639	-$577	-$492	-$380	-$303	-$383	-$451	-$465	-$6,453		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy															
27	PF Other revenues													$0		
28		$6,735	$8,129	$9,273	$7,933	$6,906	$6,378	$5,538	$5,285	$2,792	$5,340	$5,854	$6,819	$76,983		
29	**PF Partial Service**	$16,366	$19,911	$22,546	$18,855	$17,962	$16,402	$14,368	$12,230	$9,633	$12,329	$15,651	$15,085	$191,337		
30	LLH Energy Flat	314,699	357,808	388,807	397,453	342,549	332,724	314,138	373,000	283,420	319,186	294,918	307,582	4,026,284	460	4,026
31	HLH Energy Flat	560,280	639,202	693,506	683,162	637,191	627,224	585,474	596,591	519,289	539,543	584,868	546,150	7,212,480	823	7,212
32	LLH Energy Revenue Flat (40*13)/1000	$6,735	$8,129	$9,273	$7,933	$6,906	$6,378	$5,538	$5,285	$2,792	$5,340	$5,854	$6,819	$76,983		
33	HLH Energy Revenue Flat (41*14)/1000	$16,366	$19,911	$22,546	$18,855	$17,962	$16,402	$14,368	$12,230	$9,633	$12,329	$15,651	$15,085	$191,337		
34	GSP Demand	1,447	1,665	1,633	1,740	1,740	1,563	1,501	1,431	1,240	1,316	1,351	1,340	17,967		
35	Demand Revenue (44*24)	$2,764	$3,397	$3,495	$3,167	$3,219	$2,688	$2,432	$1,918	$1,525	$1,974	$2,378	$2,439	$31,394		
36	Load Variance	1,105,626	1,214,014	1,327,303	1,316,476	1,185,150	1,183,466	1,121,630	1,085,091	1,040,474	1,076,901	1,087,862	1,054,627	13,798,620	1575	13799
37	Load Variance Revenue (45*27)/1000	$509	$558	$611	$606	$545	$544	$516	$499	$479	$495	$500	$485	$6,347		
38	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	PF Other Energy															
40	PF Other revenues													$0		
41		$9,365	$11,925	$14,361	$12,755	$10,799	$10,257	$7,105	$5,151	$2,874	$6,326	$7,298	$9,903	$108,118		
42	**PF Block Service**	$16,212	$20,373	$24,827	$20,508	$20,133	$19,436	$13,534	$8,416	$7,202	$9,602	$13,344	$15,421	$189,007		
43	LLH Energy Flat	437,610	524,851	602,122	639,015	535,655	535,076	403,016	363,494	291,791	378,118	367,670	446,667	5,525,085	631	5,525
44	HLH Energy Flat	555,017	654,020	763,666	743,040	714,207	743,257	551,495	410,513	388,255	420,221	498,640	558,334	7,000,665	799	7,001
45	LLH Energy Revenue Flat (55*13)/1000	$9,365	$11,925	$14,361	$12,755	$10,799	$10,257	$7,105	$5,151	$2,874	$6,326	$7,298	$9,903	$108,118		
46	LLH Energy Revenue Stepped (56*19)/1000													$0		
47	HLH Energy Revenue Flat (56*14)/1000	$16,212	$20,373	$24,827	$20,508	$20,133	$19,436	$13,534	$8,416	$7,202	$9,602	$13,344	$15,421	$189,007		
48	HLH Energy Revenue Stepped (57*20)/1000													$0		
49	GSP Demand	1,334	1,635	1,836	1,858	1,860	1,721	1,326	1,137	1,088	1,228	1,301	1,396	17,720		
50	Demand Revenue (62*24)	$2,548	$3,335	$3,929	$3,382	$3,441	$2,960	$2,148	$1,524	$1,338	$1,842	$2,290	$2,541	$31,277		
51	LBCRAC True-up/Lookback Adjust													$0		
52	PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53	Low Density Discount Percent = 70/(59+60+61	-0.89%	-0.81%	-0.83%	-0.84%	-0.81%	-0.75%	-1.00%	-0.94%	-0.87%	-0.80%	-0.67%	-0.93%			
54	Low-Density Discount	-$251	-$290	-$358	-$308	-$278	-$245	-$228	-$143	-$99	-$143	-$154	-$260	-$2,756		
55	PF Other Energy													0		
56	PF Block Other Revenues															
57									$1,334	$1,603	$2,401	$2,517		$7,855		
58	**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,977	39,178	0	152,053	17	152
59	**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	45,461	65,398	72,150	65,015	0	248,024	28	248
60	**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$709	$721	$1,370	$1,581	$0	$4,382		
61														$0		

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1							Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4																
5																
6														**Fiscal Year 2011**		
7	WESTERN HUB	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
62																
63	**TAC LLH**													0	-	-
64	**TAC HLH**													0	-	-
65	**TAC Demand**													0		
66	**TAC Revenue**													$0		
67																
68	PF SLICE	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$415,917		
69	Percent of SLICE	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.51%	1744	
70	Slice rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
71	Slice Charges ($000) 90*91	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$415,951		
72	Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	LBCRAC True-up/Lookback Adjust													$0		
74	LDD Percentage	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75	Low-Density Discount	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$4,671		
76	Slice Other															
77	**West Hub FPS (Pre-Subscription) Sales**															
78	LLH Energy Full Service	1,312	1,284	1,312	1,376	1,152	1,244	1,216	1,376	1,216	1,376	0	0	12,864	1	13
79	LLH Energy Revenue	$27	$27	$27	$29	$24	$26	$25	$29	$25	$29	$0	$0	$267		
80	HLH Energy Full Service	1,664	1,600	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,600	0	0	16,320	2	16
81	HLH Energy Revenue	$35	$33	$35	$33	$32	$36	$35	$33	$35	$33	$0	$0	$339		
82	GSP Demand	4	4	4	4	4	4	4	4	4	4	0	0	40		
83	Demand Revenue	$32	$35	$36	$31	$31	$29	$28	$23	$21	$26	$30	$31	$353		
84	Load Variance	2,976	2,884	2,976	2,976	2,688	2,972	2,880	2,976	2,880	2,976	0	0	29184	3	29
85	Load Variance Revenue	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	$0	$13		
86	Low-Density Discount													$0		
87	LT SURPLUS FB CRAC															
88	Netrwork Wind Integration Service													$0		
89	Other Pre-Subscription revenues													$0		
90																
91	Public Agency Residential Exchange															
92	Monthly Energy Flat													0	-	-
93	Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94	Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95	GSP Demand													0		
96	GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97	Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98	**Total**	$110,894	$129,761	$145,617	$129,221	$122,351	$115,478	$99,086	$84,409	$72,528	$89,008	$101,458	$105,742	$1,305,554		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2009**															
4																
5																
6														**Fiscal Year 2009**		
7	**Eastern HUB**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8		$5,368	$6,802	$8,511	$7,275	$5,940	$5,239	$4,567	$3,496	$2,146	$4,493	$4,870	$6,311	$65,018		
9	East Hub PF Billing Determinants	$11,917	$13,246	$16,719	$14,546	$12,632	$11,143	$10,015	$7,231	$6,659	$9,099	$10,793	$11,749	$135,749		
10	**PF Full Service**	$2,227	$2,491	$3,086	$2,947	$2,744	$2,093	$1,874	$1,489	$1,396	$2,351	$2,409	$2,324	$27,430		
11	LLH Energy Flat	250,844	299,399	356,856	364,490	294,631	273,287	259,029	246,688	217,862	268,559	245,333	284,685	3,361,663	384	3,362
12	HLH Energy Flat	407,981	425,240	514,274	527,016	448,108	426,128	408,092	352,756	358,976	398,206	403,309	425,382	5,095,468	582	5,095
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat= (11*13)/1000	$5,368	$6,802	$8,511	$7,275	$5,940	$5,239	$4,567	$3,496	$2,146	$4,493	$4,870	$6,311	$65,018		
16	HLH Energy Revenue Flat= (12*14)/1000	$11,917	$13,246	$16,719	$14,546	$12,632	$11,143	$10,015	$7,231	$6,659	$9,099	$10,793	$11,749	$135,749		
17	GSP Demand	1,166	1,221	1,442	1,619	1,483	1,217	1,157	1,111	1,135	1,567	1,369	1,277	15,764	2	16
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue= (23*24)	$2,227	$2,490	$3,087	$2,947	$2,743	$2,093	$1,875	$1,488	$1,396	$2,350	$2,410	$2,325	$27,432		
20	PF Ld Variance	666,394	728,270	873,497	892,775	744,287	702,637	671,689	756,946	799,339	918,757	865,138	712,436	9,332,165	1,065	9,332
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance= (26*27)/1000	$307	$335	$401	$410	$342	$323	$309	$307	$308	$360	$343	$327	$4,072		
23	Low Density Discount Percent=28/(15+16+	-3.83%	-3.66%	-3.70%	-3.72%	-3.67%	-3.70%	-3.98%	-3.71%	-3.52%	-3.55%	-3.55%	-4.07%			
24	Low Density Discount	-$758	-$837	-$1,063	-$938	-$795	-$696	-$667	-$465	-$370	-$578	-$653	-$842	-$8,663		
25	LBCRAC True-up/Lookback Adjust	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$603	-$7,235		
26	PF Other Energy	0												0	0	0
27	PF Other Revenues	-$169												-$169		
28		$1,709	$2,230	$2,636	$2,268	$1,895	$1,761	$1,425	$1,126	$745	$1,549	$1,638	$1,903	$20,886		
29	**PF Partial Service**	$3,724	$4,244	$5,006	$4,369	$3,926	$3,627	$2,931	$2,248	$2,248	$3,000	$3,534	$3,374	$42,230		
30	LLH Energy Flat	79,872	98,172	110,507	113,639	94,008	91,865	80,822	79,443	75,667	92,580	82,528	85,852	1,084,955	124	1,085
31	HLH Energy Flat	127,480	136,240	153,992	158,279	139,284	138,684	119,422	109,656	121,177	131,293	132,068	122,171	1,589,746	181	1,590
32	LLH Energy Revenue Flat = 39*13/1000	$1,709	$2,230	$2,636	$2,268	$1,895	$1,761	$1,425	$1,126	$745	$1,549	$1,638	$1,903	$20,886		
33	HLH Energy Revenue Flat = 40*14/1000	$3,724	$4,244	$5,006	$4,369	$3,926	$3,627	$2,931	$2,248	$2,248	$3,000	$3,534	$3,374	$42,230		
34	GSP Demand	342	381	421	415	398	355	331	269	290	337	325	297	4,161		
35	Demand Revenue = 47*24	$654	$777	$901	$755	$736	$611	$536	$360	$357	$506	$572	$541	$7,305		
36	Load Variance	214,856	240,736	271,425	275,191	238,472	236,682	206,916	200,858	210,393	239,549	229,477	214,793	2,779,348	317	2,779
37	Load Variance = 49*27/1000	$99	$111	$125	$127	$110	$109	$95	$92	$97	$110	$106	$99	$1,279		
38	LBCRAC True-up/Lookback Adjust	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$188	-$2,252		
39	Low Density Discount Percent= 56/(42+43·	-2.69%	-2.35%	-2.35%	-2.21%	-2.30%	-2.34%	-2.34%	-2.31%	-2.42%	-2.41%	-2.45%	-2.66%			
40	Low Density Discount	-$167	-$173	-$204	-$166	-$153	-$143	-$117	-$88	-$84	-$124	-$144	-$157	-$1,721		
41	PF Other Energy	0												0	0	0
42	PF Other Revenue	$0												$0		
43		$2,450	$2,641	$2,924	$2,492	$2,226	$2,158	$2,208	$1,801	$1,052	$1,838	$1,923	$2,618	$26,332		
44	**PF Block Service**	$4,719	$4,114	$5,043	$4,363	$4,141	$3,737	$4,202	$2,682	$2,441	$2,709	$2,860	$4,070	$45,081		
45	LLH Energy Flat	114,504	116,241	122,581	124,862	110,401	112,587	125,243	127,087	106,824	109,867	96,891	118,103	1,385,191	158	1,385
46	HLH Energy Flat	161,568	132,060	155,127	158,074	146,904	142,900	171,239	130,828	131,616	118,569	106,867	147,340	1,703,092	194	1,703
47	LLH Energy Revenue Flat=(61*13)/1000	$2,450	$2,641	$2,924	$2,492	$2,226	$2,158	$2,208	$1,801	$1,052	$1,838	$1,923	$2,618	$26,332		
48	HLH Energy Revenue Flat=(62*14)/1000	$4,719	$4,114	$5,043	$4,363	$4,141	$3,737	$4,202	$2,682	$2,441	$2,709	$2,860	$4,070	$45,081		
49	GSP Demand	374	342	371	377	381	341	403	457	500	495	413	368	4,822		
50	Demand Revenue=(69*24)	$714	$697	$794	$687	$704	$587	$653	$613	$614	$742	$727	$669	$8,202		
51	LBCRAC True-up/Lookback Adjust	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$320	-$3,840		
52	Low-Density Discount	$0												$0		
53	PF Other Energy	0												0	0	0
54	PF Block Other Revenue	$0														
55																

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2009**															
4																
5																
6														**Fiscal Year 2009**		
7	**Eastern HUB**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
56	**PF SLICE**	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$92,564		
57	Percent of SLICE	4.1193%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	384	
58	Slice Rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
59	Slice Charges	$7,714	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$92,561		
60	LBCRAC True-up/Lookback Adjust	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$243	-$2,915		
61	Slice Other Revenues	$0														
62																
63	**East Hub FPS (Pre-Subscription) Sales**															
64	LLH Energy Pre-Sub	36,570	58,100	71,356	72,010	58,399	55,768	48,804	50,954	48,701	61,609	52,733	48,484	663,488	76	663
65	LLH Energy Revenue	$819	$1,237	$1,541	$1,514	$1,226	$1,162	$902	$524	$448	$780	$903	$1,019	$12,076		
66	HLH Energy Pre-Sub	60,392	85,037	100,228	102,597	88,277	87,630	74,790	75,799	83,085	91,980	92,307	72,031	1,014,153	116	1,014
67	HLH Energy Revenue	$1,485	$2,044	$2,440	$2,428	$2,087	$2,012	$1,542	$953	$985	$1,403	$1,877	$1,667	$20,923		
68	GSP Demand	176	245	277	290	278	234	214	186	192	245	229	200	2,766		
69	Demand Revenue	$169	$267	$305	$303	$290	$241	$213	$176	$176	$241	$235	$204	$2,820		
70	Load Variance	78,157	136,939	163,907	166,883	139,797	137,710	119,954	121,940	123,478	149,025	140,209	117,755	1,595,754	182	1,596
71	Load Variance Revenue	$45	$78	$93	$95	$80	$78	$68	$70	$70	$85	$80	$67	$911		
72	Low Density Discount	-$70	-$176	-$210	-$219	-$186	-$175	-$134	-$79	-$80	-$119	-$150	-$147	-$1,743		
73	Wind Integration Service													$0		
74	Other Presubscription revenues	$2												$2		
75	**Irrigation Mitigation**								$4,336	$5,308	$8,144	$7,986		$25,775		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,155	123,083	0	498,445	57	498
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,478	217,906	243,565	207,128	0	816,077	93	816
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,259	$1,411	$2,649	$2,875	$0	$8,194		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,293	$1,325	$2,497	$2,529	$0	$7,644		
80														$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$41,605	$46,487	$55,409	$49,616	$44,304	$40,227	$36,981	$31,448	$28,307	$39,951	$43,688	$42,158	$500,180		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														**Fiscal Year 2010**		
7	**Eastern HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8		$5,591	$7,004	$8,753	$7,574	$6,097	$5,289	$4,683	$3,597	$2,211	$4,858	$5,015	$6,461	$67,134		
9	East Hub PF Billing Determinants	$12,284	$13,620	$17,170	$14,770	$12,949	$11,528	$10,255	$7,436	$6,856	$9,011	$11,105	$12,015	$139,000		
10	**PF Full Service**	$2,515	$2,560	$3,165	$3,027	$2,814	$2,147	$1,923	$1,524	$1,430	$2,397	$2,469	$2,381	$28,352		
11	LLH Energy Flat	261,274	308,272	367,007	379,473	302,436	275,914	265,622	253,845	224,477	290,370	252,630	291,432	3,472,752	396	3,473
12	HLH Energy Flat	420,548	437,252	528,160	535,131	459,343	440,833	417,904	362,748	369,589	394,363	414,987	435,000	5,215,858	595	5,216
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat= (11*13)/1000	$5,591	$7,004	$8,753	$7,574	$6,097	$5,289	$4,683	$3,597	$2,211	$4,858	$5,015	$6,461	$67,134		
16	HLH Energy Revenue Flat= (12*14)/1000	$12,284	$13,620	$17,170	$14,770	$12,949	$11,528	$10,255	$7,436	$6,856	$9,011	$11,105	$12,015	$139,000		
17	GSP Demand	1,317	1,255	1,479	1,663	1,521	1,248	1,187	1,137	1,163	1,598	1,403	1,308	16,279		
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue= (23*24)	$2,516	$2,561	$3,165	$3,027	$2,813	$2,147	$1,924	$1,524	$1,430	$2,396	$2,469	$2,381	$28,353		
20	PF Ld Variance	684,956	749,155	897,535	915,690	763,142	719,757	687,934	774,043	816,508	936,529	883,903	728,600	9,557,752	1,091	9,558
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance= (26*27)/1000	$315	$344	$412	$421	$351	$331	$316	$315	$316	$368	$351	$335	$4,176		
23	Low Density Discount Percent=28/(15+16+	-3.81%	-3.67%	-3.72%	-3.74%	-3.69%	-3.72%	-4.00%	-3.74%	-3.55%	-3.58%	-3.58%	-4.08%			
24	Low Density Discount	-$789	-$864	-$1,096	-$965	-$820	-$719	-$687	-$481	-$384	-$595	-$677	-$864	-$8,941		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy													0	0	0
27	PF Other Revenues													$0		
28		$1,922	$2,322	$2,741	$2,392	$1,975	$1,808	$1,487	$1,180	$780	$1,677	$1,710	$1,984	$21,979		
29	**PF Partial Service**	$3,973	$4,417	$5,207	$4,503	$4,091	$3,816	$3,057	$2,354	$2,354	$3,046	$3,688	$3,517	$44,022		
30	LLH Energy Flat	89,814	102,216	114,945	119,842	97,980	94,309	84,342	83,248	79,217	100,235	86,130	89,500	1,141,778	130	1,142
31	HLH Energy Flat	136,000	141,797	160,161	163,156	145,132	145,923	124,572	114,848	126,876	133,306	137,817	127,319	1,656,907	189	1,657
32	LLH Energy Revenue Flat = 39*13/1000	$1,922	$2,322	$2,741	$2,392	$1,975	$1,808	$1,487	$1,180	$780	$1,677	$1,710	$1,984	$21,979		
33	HLH Energy Revenue Flat = 40*14/1000	$3,973	$4,417	$5,207	$4,503	$4,091	$3,816	$3,057	$2,354	$2,354	$3,046	$3,688	$3,517	$44,022		
34	GSP Demand	348	385	426	420	403	360	336	274	296	343	331	302	4,224		
35	Demand Revenue = 47*24	$664	$786	$912	$765	$745	$620	$544	$367	$364	$514	$582	$550	$7,414		
36	Load Variance	232,886	250,336	282,029	286,272	248,297	246,368	215,588	209,852	219,644	249,220	238,824	223,590	2,902,906	331	2,903
37	Load Variance = 49*27/1000	$107	$115	$130	$132	$114	$113	$99	$96	$100	$114	$109	$103	$1,332		
38	LBCRAC True-up/Lookback Adjust													$0		
39	Low Density Discount Percent= 56/(42+43	-2.50%	-2.34%	-2.34%	-2.19%	-2.29%	-2.34%	-2.34%	-2.30%	-2.41%	-2.40%	-2.44%	-2.64%			
40	Low Density Discount	-$167	-$179	-$210	-$171	-$159	-$148	-$121	-$92	-$87	-$128	-$149	-$163	-$1,774		
41	PF Other Energy													0	0	0
42	PF Other Revenue	-$116	-$125	-$141	-$143	-$124	-$123	-$108	-$105	-$110	-$125	-$119	-$112	-$1,451		
43		$2,273	$2,641	$2,924	$2,616	$2,226	$2,051	$2,208	$1,801	$1,052	$1,838	$1,923	$2,618	$26,171		
44	**PF Block Service**	$4,289	$4,114	$5,043	$4,192	$4,141	$3,883	$4,202	$2,682	$2,441	$2,709	$2,860	$4,070	$44,626		
45	LLH Energy Flat	106,199	116,241	122,581	131,065	110,401	106,994	125,243	127,087	106,824	109,867	96,891	118,103	1,377,496	157	1,377
46	HLH Energy Flat	146,826	132,060	155,127	151,870	146,904	148,493	171,239	130,828	131,616	118,569	106,867	147,340	1,687,739	193	1,688
47	LLH Energy Revenue Flat=(61*13)/1000	$2,273	$2,641	$2,924	$2,616	$2,226	$2,051	$2,208	$1,801	$1,052	$1,838	$1,923	$2,618	$26,171		
48	HLH Energy Revenue Flat=(62*14)/1000	$4,289	$4,114	$5,043	$4,192	$4,141	$3,883	$4,202	$2,682	$2,441	$2,709	$2,860	$4,070	$44,626		
49	GSP Demand	338	342	371	377	381	341	403	457	500	495	413	368	4,786		
50	Demand Revenue=(69*24)	$645	$697	$794	$687	$704	$587	$653	$613	$614	$742	$727	$669	$8,133		
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount													$0		
53	PF Other Energy													0	0	0
54	PF Block Other Revenue															
55																

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														**Fiscal Year 2010**		
7	**Eastern HUB**	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total	aMW	GWh
56	**PF SLICE**	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$92,563		
57	Percent of SLICE	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	393	
58	Slice Rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
59	Slice Charges	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$7,713	$92,561		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues															
62																
63	**East Hub FPS (Pre-Subscription) Sales**															
64	LLH Energy Pre-Sub	48,150	59,384	72,881	73,553	59,687	56,954	49,899	52,140	49,789	66,215	53,930	49,608	692,190	79	692
65	LLH Energy Revenue	$1,011	$1,265	$1,574	$1,548	$1,255	$1,188	$924	$536	$459	$838	$924	$1,044	$12,565		
66	HLH Energy Pre-Sub	76,383	86,899	102,375	104,764	90,240	89,513	76,449	77,523	84,915	90,684	94,346	73,663	1,047,754	120	1,048
67	HLH Energy Revenue	$1,814	$2,089	$2,491	$2,480	$2,134	$2,056	$1,577	$975	$1,007	$1,382	$1,918	$1,706	$21,628		
68	GSP Demand	228	249	282	294	283	239	218	190	196	250	234	204	2,867		
69	Demand Revenue	$239	$271	$310	$307	$295	$245	$216	$180	$180	$245	$239	$208	$2,935		
70	Load Variance	121,878	140,024	167,495	170,513	142,979	140,719	122,647	124,789	126,347	152,275	143,382	120,441	1,673,489	191	1,673
71	Load Variance Revenue	$69	$80	$95	$97	$82	$80	$70	$71	$72	$87	$82	$69	$955		
72	Low Density Discount	-$150	-$181	-$215	-$224	-$191	-$179	-$138	-$81	-$82	-$122	-$154	-$151	-$1,867		
73	Wind Integration Service													$0		
74	Other Presubscription revenues													$0		
75	**Irrigation Mitigation**								$4,336	$5,308	$8,144	$7,986		$25,775		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,155	123,083	0	498,445	57	498
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,478	217,906	243,565	207,128	0	816,077	93	816
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,259	$1,411	$2,649	$2,875	$0	$8,194		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,293	$1,325	$2,497	$2,529	$0	$7,644		
80														$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$44,203	$48,691	$57,772	$51,720	$46,392	$42,286	$38,876	$33,233	$30,023	$41,717	$45,721	$44,152	$524,787		

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	**Eastern HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8		$5,820	$7,076	$8,965	$7,736	$6,229	$5,404	$4,783	$3,688	$2,269	$4,836	$5,047	$6,595	$68,448		
9	East Hub PF Billing Determinants	$12,457	$14,088	$17,566	$15,072	$13,216	$11,767	$10,465	$7,619	$7,032	$9,493	$11,520	$12,253	$142,545		
10	**PF Full Service**	$2,582	$2,630	$3,249	$3,090	$2,880	$2,195	$1,965	$1,554	$1,459	$2,441	$2,519	$2,430	$28,993		
11	LLH Energy Flat	271,978	311,441	375,878	387,578	308,962	281,917	271,282	260,295	230,387	289,051	254,235	297,490	3,540,494	404	3,540
12	HLH Energy Flat	426,448	452,249	540,313	546,079	468,813	449,970	426,434	371,642	379,068	415,454	430,502	443,612	5,350,584	611	5,351
13	PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14	PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15	LLH Energy Revenue Flat= (11*13)/1000	$5,820	$7,076	$8,965	$7,736	$6,229	$5,404	$4,783	$3,688	$2,269	$4,836	$5,047	$6,595	$68,448		
16	HLH Energy Revenue Flat= (12*14)/1000	$12,457	$14,088	$17,566	$15,072	$13,216	$11,767	$10,465	$7,619	$7,032	$9,493	$11,520	$12,253	$142,545		
17	GSP Demand	1,352	1,289	1,518	1,698	1,557	1,276	1,213	1,160	1,186	1,627	1,431	1,335	16,642		
18	PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19	Demand Revenue= (23*24)	$2,582	$2,629	$3,249	$3,090	$2,881	$2,194	$1,966	$1,555	$1,459	$2,440	$2,519	$2,430	$28,992		
20	PF Ld Variance	701,360	767,128	918,355	934,739	779,133	734,922	702,325	789,448	832,139	956,591	901,036	743,259	9,760,435	1,114	9,760
21	PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22	Load Variance= (26*27)/1000	$322	$353	$422	$430	$358	$338	$323	$322	$323	$378	$359	$342	$4,269		
23	Low Density Discount Percent=28/(15+16+	-3.83%	-3.69%	-3.73%	-3.76%	-3.71%	-3.75%	-4.02%	-3.77%	-3.59%	-3.61%	-3.61%	-4.09%			
24	Low Density Discount	-$811	-$892	-$1,128	-$991	-$842	-$738	-$704	-$497	-$398	-$619	-$703	-$885	-$9,209		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy													0	0	0
27	PF Other Revenues													$0		
28		$2,035	$2,382	$2,851	$2,470	$2,043	$1,869	$1,540	$1,224	$808	$1,699	$1,739	$2,051	$22,712		
29	**PF Partial Service**	$4,097	$4,645	$5,415	$4,649	$4,229	$3,943	$3,164	$2,440	$2,437	$3,204	$3,853	$3,633	$45,707		
30	LLH Energy Flat	95,095	104,855	119,550	123,767	101,324	97,506	87,331	86,378	82,066	101,563	87,591	92,521	1,179,547	135	1,180
31	HLH Energy Flat	140,261	149,117	166,571	168,424	150,005	150,787	128,923	119,016	131,357	140,222	143,975	131,523	1,720,181	196	1,720
32	LLH Energy Revenue Flat = 39*13/1000	$2,035	$2,382	$2,851	$2,470	$2,043	$1,869	$1,540	$1,224	$808	$1,699	$1,739	$2,051	$22,712		
33	HLH Energy Revenue Flat = 40*14/1000	$4,097	$4,645	$5,415	$4,648	$4,229	$3,943	$3,164	$2,440	$2,437	$3,204	$3,853	$3,633	$45,707		
34	GSP Demand	354	391	432	427	410	367	343	280	302	349	338	308	4,301		
35	Demand Revenue = 47*24	$676	$799	$925	$776	$758	$631	$555	$375	$372	$524	$594	$561	$7,547		
36	Load Variance	242,426	260,293	293,049	295,465	256,517	254,428	222,927	217,148	226,970	257,462	246,447	230,816	3,003,948	343	3,004
37	Load Variance = 49*27/1000	$112	$120	$135	$136	$118	$117	$103	$99	$104	$117	$112	$106	$1,379		
38	LBCRAC True-up/Lookback Adjust													$0		
39	Low Density Discount Percent= 56/(42+43-	-2.48%	-2.34%	-2.32%	-2.19%	-2.30%	-2.34%	-2.35%	-2.31%	-2.42%	-2.39%	-2.45%	-2.65%			
40	Low Density Discount	-$172	-$186	-$217	-$176	-$164	-$154	-$126	-$96	-$90	-$133	-$155	-$168	-$1,835		
41	PF Other Energy													0	0	0
42	PF Other Revenue	-$121	-$130	-$147	-$148	-$128	-$127	-$111	-$109	-$113	-$129	-$123	-$115	-$1,502		
43		$2,391	$2,514	$2,924	$2,616	$2,226	$2,051	$2,208	$1,801	$1,052	$1,970	$1,793	$2,618	$26,163		
44	**PF Block Service**	$4,128	$4,288	$5,043	$4,192	$4,141	$3,883	$4,202	$2,682	$2,441	$2,554	$3,034	$4,070	$44,658		
45	LLH Energy Flat	111,707	110,641	122,581	131,065	110,401	106,994	125,243	127,087	106,824	117,765	90,326	118,103	1,378,737	157	1,379
46	HLH Energy Flat	141,318	137,660	155,127	151,870	146,904	148,493	171,239	130,828	131,616	111,758	113,363	147,340	1,687,516	193	1,688
47	LLH Energy Revenue Flat=(61*13)/1000	$2,391	$2,514	$2,924	$2,616	$2,226	$2,051	$2,208	$1,801	$1,052	$1,970	$1,793	$2,618	$26,163		
48	HLH Energy Revenue Flat=(62*14)/1000	$4,128	$4,288	$5,043	$4,192	$4,141	$3,883	$4,202	$2,682	$2,441	$2,554	$3,034	$4,070	$44,658		
49	GSP Demand	338	342	371	377	381	341	403	457	500	495	413	368	4,786		
50	Demand Revenue=(69*24)	$645	$697	$794	$687	$704	$587	$653	$613	$614	$742	$727	$669	$8,133		
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount													$0		
53	PF Other Energy													0	0	0
54	PF Block Other Revenue															
55																

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Current Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	**Eastern HUB**	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	aMW	GWh
56	**PF SLICE**	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$92,563		
57	Percent of SLICE	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	388	
58	Slice Rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
59	Slice Charges	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$7,714	$92,563		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues															
62																
63	**East Hub FPS (Pre-Subscription) Sales**	-4.59%	-4.70%	-4.64%	-4.90%	-4.91%	-4.87%	-4.78%	-4.43%	-4.60%	-4.58%	-4.66%	-4.80%			
64	LLH Energy Pre-Sub	49,234	60,709	74,446	75,122	61,011	58,170	51,030	53,355	50,914	64,534	55,169	50,759	704,453	80	704
65	LLH Energy Revenue	$1,034	$1,294	$1,609	$1,582	$1,284	$1,214	$946	$548	$470	$817	$946	$1,069	$12,812		
66	HLH Energy Pre-Sub	78,091	88,823	104,576	106,996	92,240	91,460	78,155	79,299	86,808	96,178	96,440	75,323	1,074,389	123	1,074
67	HLH Energy Revenue	$1,572	$1,812	$2,178	$2,142	$1,847	$1,813	$1,372	$865	$890	$1,249	$1,656	$1,458	$18,855		
68	GSP Demand	232	253	287	300	287	243	222	194	199	253	238	208	2,916		
69	Demand Revenue	$243	$275	$314	$312	$299	$250	$220	$184	$183	$249	$244	$211	$2,984		
70	Load Variance	124,603	143,199	171,189	174,247	146,252	143,814	125,414	127,720	129,297	156,026	146,646	123,201	1,711,608	195	1,712
71	Load Variance Revenue	$71	$82	$98	$99	$84	$82	$71	$73	$74	$89	$84	$70	$977		
72	Low Density Discount	-$134	-$163	-$195	-$203	-$173	-$163	-$125	-$74	-$74	-$110	-$136	-$135	-$1,685		
73	Wind Integration Service													$0		
74	Other Presubscription revenues													$0		
75	**Irrigation Mitigation**								$4,336	$5,308	$8,118	$7,989		$25,752		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,485	122,864	0	498,556	57	499
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,478	217,906	242,148	207,416	0	814,948	93	815
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,259	$1,411	$2,646	$2,876	$0	$8,192		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,293	$1,325	$2,485	$2,529	$0	$7,633		
80		$0												$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$44,659	$49,396	$58,514	$52,186	$46,821	$42,674	$39,217	$33,579	$30,302	$42,216	$46,227	$44,546	$530,337		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2009**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2009**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8																
9	**PF Residential Exchange**															
10	Demand (MW)	5388	5688	7179	8143	7444	5789	5801	3794	3352	3833	4456	5381	66248	8	66
11	Demand Rate															
12	HLH Energy (MWhr)	1,625,361	1,841,325	2,357,576	2,605,870	2,401,028	2,301,903	2,143,900	1,354,851	1,182,225	1,155,773	1,508,699	1,828,050	22,306,562	2,546	22,307
13	LLH Energy (MWhr)	986,431	1,061,893	1,328,339	1,712,588	1,524,682	1,392,875	1,230,499	851,046	647,173	656,823	759,372	1,019,213	13,170,934	1,504	13,171
14	Residential Exchange Rate	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)	(47.50)		
15																
16	**Residential Exchange Revenue ($000)**	-$124,070	-$137,914	-$175,096	-$205,144	-$186,487	-$175,517	-$160,297	-$104,789	-$86,904	-$86,105	-$107,742	-$135,256	-$1,685,321		
17	LB CRAC True-up/Lookback adjustment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	Demand (MW)													0		
21	HLH Energy (MWhr)													0	0	0
22	LLH Energy (MWhr)													0	0	0
23	Revenue ($ Thousand)													$0		
24	IP LBCRAC True-up													$0		
25	**PAC capacity, WNP-3 and other L-T contracts**															
26	Demand (MW)	668	832	739	739	739	657	657	805	610	761	780	598	8,585		
27	HLH Energy (MWhr)	171,719	239,003	172,903	184,668	153,494	118,170	123,404	196,810	115,061	151,662	172,526	87,762	1,887,182	215	1,887
28	LLH Energy (MWhr)	-129,870	-42,585	-40,984	-52,270	-33,598	-64,884	-58,635	-4,886	-69,318	-13,278	-20,005	-107,325	-637,638	-73	-638
29	Energy (aMW)	56	272	177	178	178	72	90	258	64	186	205	-27	1,709	143	1,250
30	Revenue ($ Thousand)	$3,951	$10,861	$10,711	$10,711	$10,140	$7,358	$7,266	$7,457	$3,942	$6,432	$7,919	$3,942	$90,689		
31																
32	**Contractual Obligations (CER)**															
33	Demand (MW)	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,273	1,273	14,996		
34	HLH Energy (MWhr)	346,350	334,728	345,886	345,886	312,413	345,886	334,263	345,886	334,728	345,886	421,922	408,312	4,222,146	482	4,222
35	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Energy (aMW)	465	465	465	465	465	465	465	465	465	465	567	567	5,783	482	
37	Revenue ($ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	$0		
38	0															
39	Monthly Trading Floor Committed Sales (MWH)	350,346												350,346	40	350
40	Monthly Trading Floor Committed Sales ($000)	$19,159												$19,159		
41																
42	Monthly Trading Floor Balancing Sales (MWH)		0	758,727	1,007,453	781,857	1,035,646	1,123,052	1,420,645	1,783,623	1,174,407	185,585	212,975	9,483,969	1,083	9,484
43	Monthly Trading Floor Balancing Sales ($000)		$0	$29,906	$43,859	$31,688	$39,237	$40,270	$42,416	$45,902	$43,146	$8,204	$9,360	$333,988		
44																
45	Other Monthly Sales (MWH)	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
46	Other Monthly Sales ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
47																
48	FPS Bookouts	-98,216	-122,762	-57,472										-278,450	-32	-278
49	Revenue reversals ($000)	-$5,185	-$5,930	-$2,795										-$13,910		
50																

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2009**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2009**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
51	**Power Purchases**															
52	**ERE Augmentation Power purchases**	8,959	9,661	10,726	9,685	9,002	8,595	7,511	10,295	11,286	11,468	11,239	8,959	117,384	13	117
53	**ERE Augmentation Purchase Expense**	$268	$299	$334	$271	$267	$238	$206	$220	$214	$258	$289	$262	$3,126		
54	**IOU Power Buyback/Deferred LB CRAC expense**															
55	Expenses ($ Thousand)													$0		
56																
57	Renewable HLH (MWH)	34,311	34,325	24,293	24,063	20,461	38,693	28,678	26,230	27,059	28,177	24,661	24,297	335,248	38	335
58	Renewable LLH (MWH)	6,519	6,070	19,295	16,521	17,703	28,514	23,689	24,297	26,321	25,352	22,458	19,996	236,737	27	237
59	Renewable Expense ($000) (included in Program Expense	$2,017	$2,071	$2,144	$2,136	$2,063	$3,364	$2,668	$2,649	$2,709	$2,734	$2,423	$2,300	$29,278		
60																
61																
62	Power Purchases Bookouts (MWH)	-98,216	-122,762	-57,472	0	0	0	0	0	0	0	0	0	-278,450	-32	-278
63	Power Purchases Reversals ($000)	-$5,185	-$5,930	-$2,795	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$13,910		
64																
65	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624													0	0	0
66	TOTAL HLH Completed: PRE 8/1/00 79620															
67	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
68	TOTAL LLH Completed: PRE 8/1/00 79621															
69																
70	PURCHASE TOTAL HLH Completed: POST 8/1/00													$0		
71	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
72	PURCHASE TOTAL LLH Completed: POST 8/1/00															
73	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
74																
75																
76	Other Committed Power Purchases (MWH)	19,627	6,799	16,720	9,859	8,284	9,801	15,033	24,268	44,612	27,856	15,507	5,796	204,162	23	204
77	Balancing Power Purchases (MWH)		-	-	-	-	-	-	-	-	-	-	-	0	0	0
78	NLS Power Purchases (MWH) 79506, 79507, 79510, 7967	490,865												490,865	56	491
79	Other Committed Purchase Power Expense ($000)	$660	$637	$1,202	$812	$643	$726	$952	$991	$1,118	$1,640	$330	$513	$10,227		
80	Balancing Purchase Power Expense ($000)		$0	$466	$4,311	$7,403	$4,301	$1,809	$503	$3,172	$3,070	$23,047	$7,761	$55,842		
81	Trading Floor Purchase Power Expense ($000)	$24,183												$24,183		
82																
83																
84	Residential Exchange Power Purchase	2,611,792	2,903,218	3,685,916	4,318,458	3,925,710	3,694,778	3,374,399	2,205,896	1,829,399	1,812,595	2,268,071	2,847,263	35,477,495	4,050	35,477
85	Residential Exchange cost	$143,831	$159,880	$202,983	$237,818	$216,189	$203,471	$185,828	$121,479	$100,745	$99,820	$124,903	$156,799	$1,953,746		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2		-1					Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2010**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8																
9	**PF Residential Exchange**															
10	Demand (MW)	5934	6279	7966	9035	8729	6370	6195	4249	3585	4090	4833	5912	73176		
11	Demand Rate															
12	HLH Energy (MWhr)	1,785,050	2,030,470	2,615,292	2,888,823	2,710,153	2,532,966	2,287,625	1,516,228	1,262,057	1,226,669	1,633,037	2,006,469	24,494,840	2,796	24,495
13	LLH Energy (MWhr)	1,079,756	1,167,413	1,470,165	1,896,075	1,719,156	1,529,673	1,307,822	950,432	686,134	692,087	816,193	1,114,604	14,429,507	1,647	14,430
14	Residential Exchange Rate	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)		
15																
16	**Residential Exchange Revenue ($000)**	-$140,818	-$157,190	-$200,818	-$235,199	-$217,720	-$199,696	-$176,732	-$121,247	-$95,762	-$94,315	-$120,390	-$153,414	-$1,913,302		
17	LB CRAC True-up/Lookback adjustment													$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	Demand (MW)	17	17	17	17	17	17	17	17	17	17	17	17	204		
21	HLH Energy (MWhr)	7,344	6,528	7,072	6,800	6,528	7,344	7,072	6,800	7,072	7,072	7,072	6,800	83,504	10	84
22	LLH Energy (MWhr)	5,304	5,729	5,576	5,848	4,896	5,287	5,168	5,848	5,168	5,576	5,576	5,440	65,416	7	65
23	Revenue ($ Thousand)	$368	$375	$406	$343	$321	$330	$299	$252	$210	$288	$337	$346	$3,875		
24	IP LBCRAC True-up													$0		
25	**PAC capacity, WNP-3 and other L-T contracts**															
26	Demand (MW)	751	863	770	770	770	688	688	888	670	685	838	658	9,039		
27	HLH Energy (MWhr)	65,203	113,205	155,066	167,528	134,573	108,217	115,324	195,151	108,395	84,266	159,606	82,702	1,489,236	170	1,489
28	LLH Energy (MWhr)	-139,245	-60,973	-31,321	-44,290	-22,119	-57,999	-54,897	-4,886	-64,258	-56,596	-18,103	-102,265	-656,952	-75	-657
29	Energy (aMW)	-100	72	166	166	167	68	84	256	61	37	190	-27	1,141	95	832
30	Revenue ($ Thousand)	$5,000	$11,295	$11,476	$11,476	$10,932	$8,278	$8,171	$8,871	$5,000	$5,000	$8,997	$5,000	$99,495		
31																
32	**Contractual Obligations (CER)**															
33	Demand (MW)	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,240	1,240	15,210		
34	HLH Energy (MWhr)	422,490	408,312	421,922	421,922	381,091	421,922	407,745	421,922	408,312	421,922	392,088	379,440	4,909,088	560	4,909
35	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Energy (aMW)	567	567	567	567	567	567	567	567	567	567	527	527	6,725	560	
37	Revenue ($ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	$0		
38	0															
39	Monthly Trading Floor Committed Sales (MWH)															
40	Monthly Trading Floor Committed Sales ($000)															
41																
42	Monthly Trading Floor Balancing Sales (MWH)	423,798	310,926	472,529	1,221,617	1,013,607	1,279,887	1,731,862	2,929,925	2,243,394	1,733,918	560,047	359,765	14,281,275	1,630	14,281
43	Monthly Trading Floor Balancing Sales ($000)	$17,392	$13,389	$20,486	$59,405	$47,227	$56,460	$70,088	$108,059	$84,185	$78,127	$27,440	$17,479	$599,737		
44																
45	Other Monthly Sales (MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
46	Other Monthly Sales ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
47																
48	FPS Bookouts															
49	Revenue reversals ($000)															
50																

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2		-1					Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2010**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
51	**Power Purchases**															
52	**ERE Augmentation Power purchases**	6,986	7,280	8,274	7,504	6,647	6,555	5,396	7,924	9,304	8,467	9,108	6,783	90,228	10	90
53	**ERE Augmentation Purchase Expense**	$236	$255	$297	$237	$221	$203	$161	$200	$214	$230	$280	$224	$2,759		
54	**IOU Power Buyback/Deferred LB CRAC expense**															
55	Expenses ($ Thousand)													$0		
56																
57	Renewable HLH (MWH)	26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,658	24,297	324,419	37	324
58	Renewable LLH (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,460	19,997	262,982	30	263
59	Renewable Expense ($000) (included in Program Expense	$2,419	$2,434	$2,358	$2,250	$2,149	$3,453	$2,750	$2,869	$2,760	$2,764	$2,435	$2,318	$30,960		
60																
61																
62	Power Purchases Bookouts (MWH)															
63	Power Purchases Reversals ($000)															
64																
65	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624	276,747	268,192	276,747	276,747	249,965	276,375	267,820	276,747	267,820	276,747	276,747	267,820	3,258,474	372	3,258
66	TOTAL HLH Completed: PRE 8/1/00 79620															
67	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
68	TOTAL LLH Completed: PRE 8/1/00 79621															
69																
70	PURCHASE TOTAL HLH Completed: POST 8/1/00	$14,763	$14,306	$14,763	$14,763	$13,334	$14,743	$14,287	$14,763	$14,287	$14,763	$14,763	$14,287	$173,821		
71	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
72	PURCHASE TOTAL LLH Completed: POST 8/1/00															
73	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
74																
75																
76	Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
77	Balancing Power Purchases (MWH)	160,110	62,465	166,715	178,595	140,645	88,227	62,620	9,612	17,643	2,004	151,469	150,820	1,190,925	136	1,191
78	NLS Power Purchases (MWH) 79506, 79507, 79510, 7967															
79	Other Committed Purchase Power Expense ($000)	$384	$390	$370	$439	$473	$145	$124	$175	$162	$117	$167	$118	$3,065		
80	Balancing Purchase Power Expense ($000)	$7,856	$2,969	$8,232	$9,954	$7,927	$4,843	$3,172	$502	$900	$107	$8,684	$8,142	$63,288		
81	Trading Floor Purchase Power Expense ($000)															
82																
83																
84	Residential Exchange Power Purchase	2,864,806	3,197,882	4,085,457	4,784,898	4,429,309	4,062,639	3,595,448	2,466,659	1,948,191	1,918,756	2,449,230	3,121,073	38,924,348	4,443	38,924
85	Residential Exchange cost	$159,426	$177,962	$227,356	$266,280	$246,491	$226,086	$200,087	$137,270	$108,417	$106,779	$136,300	$173,688	$2,166,140		

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2011**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8																
9	**PF Residential Exchange**															
10	Demand (MW)	5959	6301	7982	9027	8728	6373	6289	4344	3708	4235	4961	6017	73924		
11	Demand Rate															
12	HLH Energy (MWhr)	1,795,004	2,038,426	2,621,829	2,887,031	2,710,243	2,534,069	2,323,017	1,551,707	1,306,578	1,274,141	1,678,206	2,043,502	24,763,752	2,827	24,764
13	LLH Energy (MWhr)	1,087,169	1,173,296	1,475,108	1,895,779	1,720,058	1,531,300	1,330,001	974,378	713,191	721,860	842,186	1,137,525	14,601,852	1,667	14,602
14	Residential Exchange Rate	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)		
15																
16	**Residential Exchange Revenue ($000)**	-$143,324	-$159,711	-$203,731	-$237,838	-$220,308	-$202,161	-$181,656	-$125,616	-$100,438	-$99,256	-$125,333	-$158,185	($1,957,558)		
17	LB CRAC True-up/Lookback adjustment													$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	Demand (MW)	17	17	17	17	17	17	17	17	17	17	17	17	204		
21	HLH Energy (MWhr)	7,072	6,800	7,072	6,800	6,528	7,344	7,072	6,800	7,072	6,800	7,344	6,800	83,504	10	84
22	LLH Energy (MWhr)	5,576	5,457	5,576	5,848	4,896	5,287	5,168	5,848	5,168	5,848	5,304	5,440	65,416	7	65
23	Revenue ($ Thousand)	$366	$377	$406	$343	$321	$330	$299	$252	$210	$286	$339	$346	$3,875		
24	IP LBCRAC True-up													$0		
25	**PAC capacity, WNP-3 and other L-T contracts**															
26	Demand (MW)	728	847	754	754	754	672	672	865	670	700	684	83	8,183		
27	HLH Energy (MWhr)	59,783	112,399	151,706	163,848	131,373	104,696	111,874	190,401	108,395	83,906	92,670	1,571	1,312,622	150	1,313
28	LLH Energy (MWhr)	-129,557	-55,212	-23,232	-36,324	-15,390	-50,495	-49,437	-344	-64,258	-56,236	-76,903	-21,134	-578,522	-66	-579
29	Energy (aMW)	-94	79	173	171	173	73	87	255	61	37	21	-27	1,010	84	734
30	Revenue ($ Thousand)	$5,000	$11,143	$11,325	$11,325	$10,781	$8,126	$8,019	$8,653	$5,000	$5,000	$5,406	$20	$89,796		
31																
32	**Contractual Obligations (CER)**															
33	Demand (MW)	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	14,880		
34	HLH Energy (MWhr)	392,615	379,440	392,088	392,088	354,144	392,088	378,913	392,088	379,440	392,088	384,648	372,240	4,601,880	525	4,602
35	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Energy (aMW)	524	524	524	524	524	524	524	524	524	524	524	524	6,288	525	
37	Revenue ($ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	$0		
38	0															
39	Monthly Trading Floor Committed Sales (MWH)															
40	Monthly Trading Floor Committed Sales ($000)															
41																
42	Monthly Trading Floor Balancing Sales (MWH)	580,300	524,763	609,651	1,327,415	1,105,700	1,376,015	1,465,795	2,432,918	2,145,749	1,826,259	764,566	411,774	14,570,907	1,663	14,571
43	Monthly Trading Floor Balancing Sales ($000)	$27,298	$25,840	$30,663	$71,272	$57,856	$69,445	$67,239	$105,800	$89,507	$91,817	$41,206	$22,022	$699,967		
44																
45	Other Monthly Sales (MWH)	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
46	Other Monthly Sales ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
47																
48	FPS Bookouts															
49	Revenue reversals ($000)															
50																

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Feb 9, 2009 @ 12:45						Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2011**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
51	**Power Purchases**															
52	**ERE Augmentation Power purchases**	5,311	5,533	6,284	5,702	5,056	4,986	4,106	5,532	6,225	6,264	6,885	5,129	67,014	8	67
53	**ERE Augmentation Purchase Expense**	$179	$195	$226	$180	$168	$154	$123	$140	$143	$170	$212	$170	$2,061		
54	**IOU Power Buyback/Deferred LB CRAC expense**															
55	Expenses ($ Thousand)													$0		
56																
57	Renewable HLH (MWH)	26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,659	24,297	324,420	37	324
58	Renewable LLH (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,459	19,997	262,981	30	263
59	Renewable Expense ($000) (included in Program Expense	$2,452	$2,470	$2,391	$2,280	$2,175	$3,506	$2,788	$2,907	$2,798	$2,801	$2,467	$2,349	$31,384		
60																
61																
62	Power Purchases Bookouts (MWH)															
63	Power Purchases Reversals ($000)															
64																
65	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624	445,636	431,860	445,636	445,636	402,510	445,037	431,261	445,636	431,261	445,636	445,636	431,261	5,247,005	599	5,247
66	TOTAL HLH Completed: PRE 8/1/00 79620															
67	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
68	TOTAL LLH Completed: PRE 8/1/00 79621															
69																
70	PURCHASE TOTAL HLH Completed: POST 8/1/00	$25,714	$24,919	$25,714	$25,714	$23,225	$25,679	$24,884	$25,714	$24,884	$25,714	$25,714	$24,884	$302,757		
71	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
72	PURCHASE TOTAL LLH Completed: POST 8/1/00															
73	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
74																
75																
76	Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
77	Balancing Power Purchases (MWH)	52,945	37,139	111,049	134,257	114,924	78,016	104,280	32,455	45,273	1,054	103,329	70,508	885,228	101	885
78	NLS Power Purchases (MWH) 79506, 79507, 79510, 7967															
79	Other Committed Purchase Power Expense ($000)	$54	$60	$40	$109	$143	$145	$124	$175	$162	$117	$167	$118	$1,415		
80	Balancing Purchase Power Expense ($000)	$2,905	$1,987	$6,091	$8,213	$7,005	$4,668	$5,681	$1,844	$2,583	$64	$6,470	$4,195	$51,706		
81	Trading Floor Purchase Power Expense ($000)															
82																
83																
84	Residential Exchange Power Purchase	2,882,173	3,211,722	4,096,937	4,782,810	4,430,300	4,065,369	3,653,017	2,526,085	2,019,769	1,996,001	2,520,392	3,181,028	39,365,605	4,494	39,366
85	Residential Exchange cost	$163,534	$182,233	$232,460	$271,377	$251,375	$230,669	$207,272	$143,330	$114,602	$113,253	$143,007	$180,492	$2,233,604		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1								Revenues at Current Rates								
2								Revenue ($ Thousands)								
3								**Fiscal Year 2009**								
4																
5																
6														**Fiscal Year 2009**		
7		**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8																
9	**Generation Inputs**															
10																
11	Federal Remedial Action Scheme	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$396		
12	Synchronous Condensor Operations	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$4,091		
13	Station Service	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$2,089		
14	Redispatch Service	$8	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$1,383		
15	Within hour Balancing Service for Wind Integration	$738	$738	$738	$1,492	$1,492	$1,492	$1,492	$1,492	$1,492	$1,492	$2,120	$2,120	$16,893		
16	Operating Reserves	$2,395	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$31,316		
17	Regulating Reserves	$1,279	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$1,097	$13,341		
18	BOR Network/Delivery Facilities	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$7,397		
19	Generation Integration/Energy Imbalance	$108	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$108		
20	**Total Interbusiness Line**	**$5,693**	**$5,753**	**$5,753**	**$6,507**	**$6,507**	**$6,507**	**$6,507**	**$6,507**	**$6,507**	**$6,507**	**$7,135**	**$7,135**	**$77,014**		
21																
22	**RESERVE SERVICES:**															
23	External	$146	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$3,474		
24	Total External	$146	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$3,474		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$146**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$3,474**		
29	**TOTAL Ancillary and Reserves**	**$5,839**	**$6,056**	**$6,056**	**$6,809**	**$6,809**	**$6,809**	**$6,809**	**$6,809**	**$6,809**	**$6,809**	**$7,437**	**$7,437**	**$80,488**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$882	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$9,072		
34	Slice True-Up (and Implementation costs)												$6,942	$6,942		
35	Misc. Generation	$249	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,384		
36	Energy Efficiency Rev's	$2,431	$1,500	$1,667	$1,400	$1,300	$1,300	$1,600	$1,800	$1,600	$2,000	$2,700	$2,700	$21,998		
37	Green Tags and Green Premiums Bulk	$14	$90	$90	$96	$90	$90	$90	$90	$90	$90	$90	$147	$1,069		
38	Green Premium West	$150	$23	$24	$24	$22	$24	$23	$24	$23	$24	$24	$23	$407		
39	Green Premium East	$111	$110	$113	$113	$102	$113	$110	$113	$110	$113	$113	$110	$1,332		
40	4(h)(10)c credit	$7,547	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$7,028	$84,851		
41	Network Wind Integration&Shaping	$169	$166	$166	$166	$159	$159	$159	$159	$159	$159	$159	$159	$1,936		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$11,937**	**$10,295**	**$10,466**	**$10,205**	**$10,079**	**$10,096**	**$10,411**	**$10,644**	**$10,459**	**$10,882**	**$11,574**	**$18,541**	**$135,590**		
46																
47	**Trading Floor Transmission**	**$6,514**	**$6,669**	**$6,669**	**$6,669**	**$6,669**	**$6,669**	**$6,669**	**$6,470**	**$6,470**	**$6,470**	**$6,306**	**$6,306**	**$78,547**		
48	**Other Transmission Expenses**	**$2,216**	**$2,061**	**$2,061**	**$2,061**	**$2,061**	**$2,061**	**$2,061**	**$2,260**	**$2,260**	**$2,260**	**$2,424**	**$2,424**	**$26,211**		

Table 4.6.1 Summary of Revenues at Current Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1							Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4																
5																
6														**Fiscal Year 2010**		
7		**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8																
9	**Generation Inputs**															
10																
11	Federal Remedial Action Scheme	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$396		
12	Synchronous Condensor Operations	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$1,702		
13	Station Service	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$1,900		
14	Redispatch Service	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$1,500		
15	Within hour Balancing Service for Wind Integration	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$98,439		
16	Operating Reserves	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$34,658		
17	Regulating Reserves	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$9,298		
18	BOR Network/Delivery Facilities	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$7,397		
19	Generation Integration/Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
20	**Total Interbusiness Line**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$155,290**		
21																
22	**RESERVE SERVICES:**															
23	External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
24	Total External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
29	**TOTAL Ancillary and Reserves**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$155,290**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$731	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$8,921		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,660	$5,660		
35	Misc. Generation	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,420		
36	Energy Efficiency Rev's	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$2,733	$2,733	$2,733	$20,500		
37	Green Tags and Green Premiums Bulk	$404	$378	$357	$320	$296	$589	$446	$489	$467	$477	$423	$394	$5,040		
38	Green Premium West	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	Green Premium East	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
40	4(h)(10)c credit	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$88,705		
41	Network Wind Integration&Shaping	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$1,905		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$10,721**	**$10,674**	**$10,653**	**$10,617**	**$10,593**	**$10,889**	**$10,765**	**$10,837**	**$10,835**	**$12,229**	**$12,168**	**$17,771**	**$138,751**		
46																
47	**Trading Floor Transmission**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$84,462**		
48	**Other Transmission Expenses**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$30,159**		

Table 4.6.1 Summary of Revenues at Current Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1							Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4																
5																
6															**Fiscal Year 2011**	
7		**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8																
9	**Generation Inputs**															
10																
11	Federal Remedial Action Scheme	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$396		
12	Synchronous Condensor Operations	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$142	$1,702		
13	Station Service	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$158	$1,900		
14	Redispatch Service	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$1,500		
15	Within hour Balancing Service for Wind Integration	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$8,203	$98,439		
16	Operating Reserves	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$2,888	$34,658		
17	Regulating Reserves	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$775	$9,298		
18	BOR Network/Delivery Facilities	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$7,397		
19	Generation Integration/Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
20	**Total Interbusiness Line**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$155,290**		
21																
22	**RESERVE SERVICES:**															
23	External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
24	Total External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
29	**TOTAL Ancillary and Reserves**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$12,941**	**$155,290**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$731	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$8,921		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
35	Misc. Generation	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,420		
36	Energy Efficiency Rev's	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$2,733	$2,733	$2,733	$20,500		
37	Green Tags and Green Premiums Bulk	$404	$378	$357	$320	$296	$589	$446	$489	$467	$477	$423	$394	$5,040		
38	Green Premium West	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	Green Premium East	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
40	4(h)(10)c credit	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$89,975		
41	Network Wind Integration&Shaping	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$1,905		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$10,826**	**$10,780**	**$10,759**	**$10,722**	**$10,699**	**$10,995**	**$10,871**	**$10,942**	**$10,940**	**$12,335**	**$12,273**	**$12,217**	**$134,361**		
46																
47	**Trading Floor Transmission**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$82,331**		
48	**Other Transmission Expenses**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$29,049**		

Table 4.6.2 Summary of Revenues at Proposed Rates

	A	D	E	F	G
2		**FY 2010**		**FY 2011**	
3		**($000)**	**aMW**	**($000)**	**aMW**
4	**PF Preference**	$1,391,405	5,433	$1,409,986	5,508
5	**PF Slice**	$551,956	2,157	$551,959	2,132
6	**Pre-sub/Hungry Horse**	$38,289	203	$35,903	206
7	**Irrigation Mitigation**	$23,504	196	$23,487	196
8	**Slice true-up**	$5,660	0	$0	0
9	**Industrial Power**	$5,416	17	$5,417	17
10	**Long-Term Obligations**	$99,495	655	$89,796	609
11	**Generation Inputs**	$180,452	0	$215,811	0
12	**4h10C credits**	$88,705	0	$89,975	0
13	**Colville credits**	$4,600	0	$4,600	0
14	**EE and misc revenues**	$30,865	0	$30,865	0
15	**DSB/IPP/Reserve Energy**	$8,921	159	$8,921	159
16	**Secondary Sales**	$599,737	1,630	$699,967	1,663
17					
18	**Ad hoc Gen Input adjustment**	($34,620)	0	($34,620)	0
19	**Total Revenue**	$2,994,386	10,450	$3,132,066	10,491
20					
21	**Purchases**				
22	**Augmentation Purchases**	$176,580	382	$304,818	607
23	**Secondary Purchases**	$97,340	135	$53,121	109
24					

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														**Fiscal Year 2010**		
7	WESTERN HUB	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8		$6,592	$8,997	$10,497	$8,833	$7,444	$6,846	$5,870	$4,522	$2,741	$5,119	$5,563	$6,434	$79,459		
9	**West Hub PF Billing Determinants**	$14,983	$18,244	$21,464	$18,311	$16,577	$15,269	$12,922	$9,714	$8,605	$10,044	$12,716	$12,444	$171,293		
10	**PF Full Service**	$3,294	$3,836	$4,319	$3,822	$3,788	$3,148	$2,642	$1,735	$1,524	$1,924	$2,183	$2,220	$34,434		
11	LLH Energy Flat	279,562	359,317	399,260	401,505	335,036	324,157	301,947	289,693	252,349	277,629	254,261	263,385	3,738,101	427	3738
12	HLH Energy Flat	465,445	531,433	599,040	601,950	533,546	529,803	477,886	430,014	420,788	398,902	431,192	408,664	5,828,663	665	5829
13	PF Flat LLH Energy Rate	$23.58	$25.04	$26.29	$22.00	$22.22	$21.12	$19.44	$15.61	$10.86	$18.44	$21.88	$24.43			
14	PF Flat HLH Energy Rate	$32.19	$34.33	$35.83	$30.42	$31.07	$28.82	$27.04	$22.59	$20.45	$25.18	$29.49	$30.45			
15	LLH Energy Revenue Flat Revenue = 11*13/1000	$6,605	$9,012	$10,512	$8,847	$7,456	$6,858	$5,880	$4,532	$2,746	$5,130	$5,576	$6,448	$79,603		
16	HLH Energy Revenue Flat Revenue= 12*14/1000	$15,007	$18,406	$21,538	$18,415	$16,724	$15,291	$12,978	$9,791	$8,648	$10,097	$12,777	$12,547	$172,220		
17	Demand	1,561	1,705	1,830	1,911	1,857	1,657	1,484	1,172	1,129	1,159	1,125	1,110	17,700		
18	PF GSP Demand Rate	$2.11	$2.25	$2.36	$2.00	$2.04	$1.90	$1.78	$1.48	$1.35	$1.66	$1.94	$2.00			
19	Demand Revenue = 17*18	$3,293	$3,836	$4,318	$3,823	$3,789	$3,149	$2,642	$1,735	$1,524	$1,925	$2,182	$2,220	$34,436		
20	Load Variance	816,107	965,561	1,074,418	1,079,882	939,095	927,201	853,616	800,138	748,975	752,874	760,820	742,444	10,461,131	1194	10461
21	PF Ld Variance Rate	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51			
22	Load Variance Revenue = 20*21/1000	$416	$492	$548	$551	$479	$473	$435	$408	$382	$384	$388	$379	$5,335		
23	Low Density Discount Percent															
24	Low Density Discount	-$583	-$745	-$877	-$769	-$690	-$622	-$529	-$409	-$325	-$408	-$483	-$498	-$6,938		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy															
27	PF Other revenues													$0		
28		$6,960	$9,104	$10,004	$8,521	$7,404	$6,838	$5,936	$5,682	$2,987	$5,434	$6,521	$7,298	$82,687		
29	**PF Partial Service**	$18,006	$20,978	$24,267	$20,231	$19,257	$17,588	$15,394	$13,141	$10,311	$13,537	$16,398	$16,161	$205,269		
30	LLH Energy Flat	295,151	363,573	380,516	387,296	333,208	323,768	305,359	363,973	275,065	294,708	298,012	298,723	3,919,352	447	3,919
31	HLH Energy Flat	559,373	611,063	677,282	665,044	619,799	610,276	569,312	581,732	504,222	537,595	556,039	530,747	7,022,484	802	7,022
32	LLH Energy Revenue Flat (30*13)/1000	$6,960	$9,104	$10,004	$8,521	$7,404	$6,838	$5,936	$5,682	$2,987	$5,434	$6,521	$7,298	$82,687		
33	HLH Energy Revenue Flat (31*14)/1000	$18,006	$20,978	$24,267	$20,231	$19,257	$17,588	$15,394	$13,141	$10,311	$13,537	$16,398	$16,161	$205,269		
34	GSP Demand	1,426	1,613	1,594	1,695	1,696	1,522	1,460	1,393	1,202	1,300	1,297	1,300	17,498		
35	Demand Revenue (34*18)	$3,009	$3,629	$3,762	$3,390	$3,459	$2,892	$2,599	$2,061	$1,623	$2,158	$2,517	$2,600	$33,702		
36	Load Variance	1,091,374	1,199,153	1,311,354	1,296,845	1,166,316	1,164,957	1,103,375	1,067,278	1,022,863	1,056,823	1,068,637	1,036,552	13,585,527	1551	13586
37	Load Variance Revenue (36*21)/1000	$557	$612	$669	$661	$595	$594	$563	$544	$522	$539	$545	$529	$6,929		
38	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	PF Other Energy															
40	PF Other revenues													$0		
41		$9,817	$13,794	$15,830	$14,058	$11,902	$11,301	$7,835	$5,674	$3,169	$6,593	$8,549	$10,943	$119,466		
42	**PF Block Service**	$18,557	$21,549	$27,362	$22,603	$22,190	$21,421	$14,912	$9,273	$7,940	$11,017	$14,202	$17,050	$208,077		
43	LLH Energy Flat	416,347	550,868	602,122	639,015	535,655	535,076	403,016	363,494	291,791	357,555	390,742	447,947	5,533,628	632	5,534
44	HLH Energy Flat	576,480	627,695	763,666	743,040	714,207	743,257	551,495	410,513	388,255	437,536	481,595	559,934	6,997,673	799	6,998
45	LLH Energy Revenue Flat (43*13)/1000	$9,817	$13,794	$15,830	$14,058	$11,902	$11,301	$7,835	$5,674	$3,169	$6,593	$8,549	$10,943	$119,466		
46	LLH Energy Revenue Stepped (56*19)/1000													$0		
47	HLH Energy Revenue Flat (44*14)/1000	$18,557	$21,549	$27,362	$22,603	$22,190	$21,421	$14,912	$9,273	$7,940	$11,017	$14,202	$17,050	$208,077		
48	HLH Energy Revenue Stepped (57*20)/1000													$0		
49	GSP Demand	1,334	1,635	1,836	1,858	1,860	1,721	1,326	1,137	1,088	1,225	1,308	1,400	17,728		
50	Demand Revenue (49*24)	$2,816	$3,678	$4,332	$3,715	$3,794	$3,269	$2,360	$1,683	$1,469	$2,034	$2,538	$2,800	$34,487		
51	LBCRAC True-up/Lookback Adjust													$0		
52	PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53	Low Density Discount Percent = 70/(59+60+61+62+64)	-0.89%	-0.81%	-0.83%	-0.84%	-0.81%	-0.75%	-1.00%	-0.94%	-0.87%	-0.78%	-0.71%	-0.95%			
54	Low-Density Discount	-$278	-$318	-$395	-$339	-$307	-$270	-$251	-$157	-$109	-$154	-$179	-$293	-$3,049		
55	PF Other Energy													0		
56	PF Block Other Revenues															
57									$1,470	$1,767	$2,675	$2,748		$8,661		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1								Revenues at Proposed Rates								
2								Revenue ($ Thousands)								
3								**Fiscal Year 2010**								
4																
5																
6														**Fiscal Year 2010**		
7	WESTERN HUB	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
58	**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,975	39,179	0	152,052	17	152
59	**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	45,477	65,398	73,313	64,132	0	248,320	28	248
60	**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$838	$876	$1,616	$1,807	$0	$5,137		
61														$0		
62																
63	**Pt Townsend LLH**													0	-	-
64	**Pt Townsend HLH**													0	-	-
65	**Pt Townsend Demand**													0		
66	**Pt Townsend Revenues**													$0		
67																
68	PF SLICE	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$455,256		
69	Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1765	
70	Slice rate	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050			
71	Slice Charges ($000) = 69*70*100	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$455,293		
72	Monetary Benefits to IOUs ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	LBCRAC True-up/Lookback Adjust													$0		
74	LDD Percentage	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%			
75	Low-Density Discount	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$4,652		
76	Slice Other															
77	**West Hub FPS (Pre-Subscription) Sales**															
78	LLH Energy Full Service	1,248	1,348	1,312	1,376	1,152	1,244	1,216	1,376	1,216	1,312	1,312	1,280	15,392	2	15
79	LLH Energy Revenue	$26	$28	$27	$29	$24	$26	$25	$29	$25	$27	$27	$27	$320		
80	HLH Energy Full Service	1,728	1,536	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,664	1,664	1,600	19,648	2	20
81	HLH Energy Revenue	$36	$32	$35	$33	$32	$36	$35	$33	$35	$35	$35	$33	$408		
82	GSP Demand	4	4	4	4	4	4	4	4	4	4	4	4	48		
83	Demand Revenue	$36	$38	$40	$34	$35	$32	$30	$25	$23	$28	$33	$34	$389		
84	Load Variance	2,976	2,884	2,976	2,976	2,688	2,972	2,880	2,976	2,880	2,976	2,976	2,880	35040	4	35
85	Load Variance Revenue	$2	$1	$2	$2	$1	$2	$1	$2	$1	$2	$2	$1	$18		
86	Low-Density Discount													$0		
87	LT SURPLUS FB CRAC															
88	Netrwork Wind Integration Service													$0		
89	Other Pre-Subscription revenues													$0		
90																
91	Public Agency Residential Exchange															
92	Monthly Energy Flat													0	-	-
93	Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94	Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95	GSP Demand													0		
96	GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97	Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98	**Total**	$121,835	$141,681	$159,527	$141,357	$133,699	$126,430	$108,399	$92,438	$79,400	$97,548	$110,988	$115,833	$1,429,136		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1								Revenues at Proposed Rates								
2								Revenue ($ Thousands)								
3								**Fiscal Year 2011**								
4																
5																
6														**Fiscal Year 2011**		
7	WESTERN HUB	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	aMW	GWh
8		$6,628	$8,952	$10,509	$8,860	$7,520	$6,856	$5,877	$4,518	$2,745	$4,934	$5,520	$6,438	$79,357		
9	**West Hub PF Billing Determinants**	$14,985	$18,571	$21,596	$18,506	$16,894	$15,330	$13,005	$9,814	$8,677	$10,415	$12,861	$12,588	$173,241		
10	**PF Full Service**	$3,349	$3,897	$4,383	$3,874	$3,843	$3,188	$2,681	$1,766	$1,553	$1,962	$2,225	$2,260	$34,980		
11	LLH Energy Flat	281,088	357,506	399,739	402,718	338,453	324,639	302,309	289,440	252,723	267,555	252,278	263,534	3,731,982	426	3732
12	HLH Energy Flat	465,526	540,957	602,741	608,336	543,753	531,908	480,950	434,442	424,298	413,608	436,118	413,384	5,896,021	673	5896
13	PF Flat LLH Energy Rate	$23.58	$25.04	$26.29	$22.00	$22.22	$21.12	$19.44	$15.61	$10.86	$18.44	$21.88	$24.43			
14	PF Flat HLH Energy Rate	$32.19	$34.33	$35.83	$30.42	$31.07	$28.82	$27.04	$22.59	$20.45	$25.18	$29.49	$30.45			
15	LLH Energy Revenue Flat Revenue = 11*13/1000	$6,628	$8,952	$10,509	$8,859	$7,520	$6,856	$5,877	$4,518	$2,745	$4,934	$5,520	$6,438	$79,354		
16	HLH Energy Revenue Flat Revenue= 12*14/1000	$14,985	$18,570	$21,595	$18,505	$16,894	$15,329	$13,004	$9,814	$8,676	$10,414	$12,860	$12,587	$173,234		
17	Demand	1,587	1,732	1,857	1,937	1,884	1,678	1,506	1,193	1,150	1,182	1,147	1,130	17,983		
18	PF GSP Demand Rate	$2.11	$2.25	$2.36	$2.00	$2.04	$1.90	$1.78	$1.48	$1.35	$1.66	$1.94	$2.00			
19	Demand Revenue = 17*18	$3,349	$3,897	$4,383	$3,874	$3,843	$3,188	$2,681	$1,766	$1,553	$1,962	$2,225	$2,260	$34,980		
20	Load Variance	833,329	984,397	1,092,895	1,100,436	962,825	945,415	870,831	817,277	766,655	771,772	778,069	759,780	10,683,681	1220	10684
21	PF Ld Variance Rate	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51			
22	Load Variance Revenue = 20*21/1000	$425	$502	$557	$561	$491	$482	$444	$417	$391	$394	$397	$387	$5,449		
23	Low Density Discount Percent															
24	Low Density Discount	-$600	-$764	-$897	-$783	-$705	-$636	-$542	-$419	-$334	-$423	-$498	-$513	-$7,113		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy															
27	PF Other revenues													$0		
28		$7,421	$8,960	$10,222	$8,744	$7,611	$7,027	$6,107	$5,823	$3,078	$5,886	$6,453	$7,514	$84,845		
29	**PF Partial Service**	$18,035	$21,944	$24,848	$20,782	$19,798	$18,077	$15,831	$13,477	$10,619	$13,586	$17,248	$16,630	$210,875		
30	LLH Energy Flat	314,699	357,808	388,807	397,453	342,549	332,724	314,138	373,000	283,420	319,186	294,918	307,582	4,026,284	460	4,026
31	HLH Energy Flat	560,280	639,202	693,506	683,162	637,191	627,224	585,474	596,591	519,289	539,543	584,868	546,150	7,212,480	823	7,212
32	LLH Energy Revenue Flat (30*13)/1000	$7,421	$8,960	$10,222	$8,744	$7,611	$7,027	$6,107	$5,823	$3,078	$5,886	$6,453	$7,514	$84,845		
33	HLH Energy Revenue Flat (31*14)/1000	$18,035	$21,944	$24,848	$20,782	$19,798	$18,077	$15,831	$13,477	$10,619	$13,586	$17,248	$16,630	$210,875		
34	GSP Demand	1,447	1,665	1,633	1,740	1,740	1,563	1,501	1,431	1,240	1,316	1,351	1,340	17,967		
35	Demand Revenue (34*18)	$3,053	$3,746	$3,854	$3,480	$3,550	$2,970	$2,672	$2,118	$1,674	$2,185	$2,621	$2,680	$34,602		
36	Load Variance	1,105,626	1,214,014	1,327,303	1,316,476	1,185,150	1,183,466	1,121,630	1,085,091	1,040,474	1,076,901	1,087,862	1,054,627	13,798,620	1575	13799
37	Load Variance Revenue (36*21)/1000	$564	$619	$677	$671	$604	$604	$572	$553	$531	$549	$555	$538	$7,037		
38	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	PF Other Energy															
40	PF Other revenues													$0		
41		$10,319	$13,142	$15,830	$14,058	$11,902	$11,301	$7,835	$5,674	$3,169	$6,972	$8,045	$10,912	$119,159		
42	**PF Block Service**	$17,866	$22,453	$27,362	$22,603	$22,190	$21,421	$14,912	$9,273	$7,940	$10,581	$14,705	$17,001	$208,308		
43	LLH Energy Flat	437,610	524,851	602,122	639,015	535,655	535,076	403,016	363,494	291,791	378,118	367,670	446,667	5,525,085	631	5,525
44	HLH Energy Flat	555,017	654,020	763,666	743,040	714,207	743,257	551,495	410,513	388,255	420,221	498,640	558,334	7,000,665	799	7,001
45	LLH Energy Revenue Flat (43*13)/1000	$10,319	$13,142	$15,830	$14,058	$11,902	$11,301	$7,835	$5,674	$3,169	$6,972	$8,045	$10,912	$119,159		
46	LLH Energy Revenue Stepped (56*19)/1000													$0		
47	HLH Energy Revenue Flat (44*14)/1000	$17,866	$22,452	$27,362	$22,603	$22,190	$21,421	$14,912	$9,273	$7,940	$10,581	$14,705	$17,001	$208,308		
48	HLH Energy Revenue Stepped (57*20)/1000													$0		
49	GSP Demand	1,334	1,635	1,836	1,858	1,860	1,721	1,326	1,137	1,088	1,228	1,301	1,396	17,720		
50	Demand Revenue (49*24)	$2,815	$3,679	$4,333	$3,716	$3,794	$3,270	$2,360	$1,683	$1,469	$2,038	$2,524	$2,792	$34,473		
51	LBCRAC True-up/Lookback Adjust													$0		
52	PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53	Low Density Discount Percent = 70/(59+60+61+62+64)	-0.89%	-0.81%	-0.83%	-0.84%	-0.81%	-0.75%	-1.00%	-0.94%	-0.87%	-0.80%	-0.67%	-0.93%			
54	Low-Density Discount	-$276	-$320	-$395	-$339	-$307	-$270	-$251	-$157	-$109	-$157	-$170	-$287	-$3,038		
55	PF Other Energy													0		
56	PF Block Other Revenues															
57									$1,470	$1,767	$2,646	$2,775		$8,657		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	WESTERN HUB	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
58	**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,977	39,178	0	152,053	17	152
59	**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	45,461	65,398	72,150	65,015	0	248,024	28	248
60	**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$838	$876	$1,601	$1,823	$0	$5,137		
61														$0		
62																
63	**Pt Townsend LLH**													0	-	-
64	**Pt Townsend HLH**													0	-	-
65	**Pt Townsend Demand**													0		
66	**Pt Townsend Revenues**													$0		
67																
68	PF SLICE	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$37,938	$455,256		
69	Percent of SLICE	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.509%	18.51%	1744	
70	Slice rate	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050			
71	Slice Charges ($000) = 69*70*100	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$37,941	$455,293		
72	Monetary Benefits to IOUs ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	LBCRAC True-up/Lookback Adjust													$0		
74	LDD Percentage	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%	-1.02%			
75	Low-Density Discount	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$388	-$4,653		
76	Slice Other															
77	**West Hub FPS (Pre-Subscription) Sales**															
78	LLH Energy Full Service	1,312	1,284	1,312	1,376	1,152	1,244	1,216	1,376	1,216	1,376	0	0	12,864	1	13
79	LLH Energy Revenue	$27	$27	$27	$29	$24	$26	$25	$29	$25	$29	$0	$0	$267		
80	HLH Energy Full Service	1,664	1,600	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,600	0	0	16,320	2	16
81	HLH Energy Revenue	$35	$33	$35	$33	$32	$36	$35	$33	$35	$33	$0	$0	$339		
82	GSP Demand	4	4	4	4	4	4	4	4	4	4	0	0	40		
83	Demand Revenue	$36	$38	$40	$34	$35	$32	$30	$25	$23	$28	$33	$34	$389		
84	Load Variance	2,976	2,884	2,976	2,976	2,688	2,972	2,880	2,976	2,880	2,976	0	0	29184	3	29
85	Load Variance Revenue	$2	$1	$2	$2	$1	$2	$1	$2	$1	$2	$0	$0	$15		
86	Low-Density Discount													$0		
87	LT SURPLUS FB CRAC															
88	Netrwork Wind Integration Service													$0		
89	Other Pre-Subscription revenues													$0		
90																
91	Public Agency Residential Exchange															
92	Monthly Energy Flat													0	-	-
93	Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94	Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95	GSP Demand													0		
96	GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97	Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98	**Total**	$122,235	$143,033	$160,535	$142,383	$134,833	$127,267	$109,146	$93,018	$79,914	$98,166	$111,893	$116,528	$1,438,951		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														**Fiscal Year 2010**		
7	**Eastern HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8		$6,161	$7,719	$9,649	$8,348	$6,720	$5,827	$5,164	$3,963	$2,438	$5,354	$5,528	$7,120	$73,990		
9	East Hub PF Billing Determinants	$13,537	$15,011	$18,924	$16,279	$14,272	$12,705	$11,300	$8,194	$7,558	$9,930	$12,238	$13,246	$153,194		
10	**PF Full Service**	$2,779	$2,824	$3,490	$3,326	$3,103	$2,371	$2,113	$1,683	$1,570	$2,653	$2,722	$2,616	$31,249		
11	LLH Energy Flat	261,274	308,272	367,007	379,473	302,436	275,914	265,622	253,845	224,477	290,370	252,630	291,432	3,472,752	396	3,473
12	HLH Energy Flat	420,548	437,252	528,160	535,131	459,343	440,833	417,904	362,748	369,589	394,363	414,987	435,000	5,215,858	595	5,216
13	PF Flat LLH Energy Rate	$23.58	$25.04	$26.29	$22.00	$22.22	$21.12	$19.44	$15.61	$10.86	$18.44	$21.88	$24.43			
14	PF Flat HLH Energy Rate	$32.19	$34.33	$35.83	$30.42	$31.07	$28.82	$27.04	$22.59	$20.45	$25.18	$29.49	$30.45			
15	LLH Energy Revenue Flat= (11*13)/1000	$6,161	$7,719	$9,649	$8,348	$6,720	$5,827	$5,164	$3,963	$2,438	$5,354	$5,528	$7,120	$73,990		
16	HLH Energy Revenue Flat= (12*14)/1000	$13,537	$15,011	$18,924	$16,279	$14,272	$12,705	$11,300	$8,194	$7,558	$9,930	$12,238	$13,246	$153,194		
17	GSP Demand	1,317	1,255	1,479	1,663	1,521	1,248	1,187	1,137	1,163	1,598	1,403	1,308	16,279		
18	PF GSP Demand Rate	$2.11	$2.25	$2.36	$2.00	$2.04	$1.90	$1.78	$1.48	$1.35	$1.66	$1.94	$2.00			
19	Demand Revenue= (18*17)	$2,780	$2,824	$3,490	$3,326	$3,102	$2,372	$2,114	$1,683	$1,570	$2,652	$2,722	$2,617	$31,251		
20	PF Ld Variance	684,956	749,155	897,535	915,690	763,142	719,757	687,934	774,043	816,508	936,529	883,903	728,600	9,557,752	1,091	9,558
21	PF Ld Variance Rate	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51			
22	Load Variance= (20*21)/1000	$349	$382	$457	$467	$389	$367	$350	$350	$350	$408	$390	$371	$4,630		
23	Low Density Discount Percent=28/(15+16+	-3.81%	-3.67%	-3.72%	-3.74%	-3.69%	-3.72%	-4.00%	-3.74%	-3.55%	-3.58%	-3.58%	-4.08%			
24	Low Density Discount	-$870	-$952	-$1,208	-$1,063	-$904	-$792	-$756	-$531	-$424	-$656	-$747	-$952	-$9,856		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy													0	0	0
27	PF Other Revenues													$0		
28		$2,118	$2,559	$3,022	$2,637	$2,177	$1,992	$1,640	$1,300	$860	$1,848	$1,885	$2,186	$24,223		
29	**PF Partial Service**	$4,378	$4,868	$5,739	$4,963	$4,509	$4,206	$3,368	$2,594	$2,595	$3,357	$4,064	$3,877	$48,517		
30	LLH Energy Flat	89,814	102,216	114,945	119,842	97,980	94,309	84,342	83,248	79,217	100,235	86,130	89,500	1,141,778	130	1,142
31	HLH Energy Flat	136,000	141,797	160,161	163,156	145,132	145,923	124,572	114,848	126,876	133,306	137,817	127,319	1,656,907	189	1,657
32	LLH Energy Revenue Flat = 30*13/1000	$2,118	$2,559	$3,022	$2,637	$2,177	$1,992	$1,640	$1,299	$860	$1,848	$1,885	$2,186	$24,223		
33	HLH Energy Revenue Flat = 31*14/1000	$4,378	$4,868	$5,739	$4,963	$4,509	$4,205	$3,368	$2,594	$2,595	$3,357	$4,064	$3,877	$48,517		
34	GSP Demand	348	385	426	420	403	360	336	274	296	343	331	302	4,224		
35	Demand Revenue = 34*17	$734	$867	$1,005	$840	$822	$685	$598	$406	$399	$569	$642	$604	$8,171		
36	Load Variance	232,886	250,336	282,029	286,272	248,297	246,368	215,588	209,852	219,644	249,220	238,824	223,590	2,902,906	331	2,903
37	Load Variance = 36*21/1000	$119	$128	$144	$146	$127	$126	$110	$107	$111	$126	$121	$114	$1,477		
38	LBCRAC True-up/Lookback Adjust													$0		
39	Low Density Discount Percent= 56/(42+43+	-2.50%	-2.34%	-2.34%	-2.19%	-2.29%	-2.34%	-2.34%	-2.30%	-2.41%	-2.40%	-2.44%	-2.64%			
40	Low Density Discount	-$184	-$197	-$232	-$188	-$175	-$164	-$134	-$101	-$96	-$142	-$164	-$179	-$1,955		
41	PF Other Energy													0	0	0
42	PF Other Revenue	-$116	-$125	-$141	-$143	-$124	-$123	-$108	-$105	-$110	-$125	-$119	-$112	-$1,451		
43		$2,504	$2,911	$3,223	$2,883	$2,453	$2,260	$2,435	$1,984	$1,160	$2,026	$2,120	$2,885	$28,844		
44	**PF Block Service**	$4,726	$4,534	$5,558	$4,620	$4,564	$4,280	$4,630	$2,955	$2,692	$2,986	$3,152	$4,487	$49,183		
45	LLH Energy Flat	106,199	116,241	122,581	131,065	110,401	106,994	125,243	127,087	106,824	109,867	96,891	118,103	1,377,496	157	1,377
46	HLH Energy Flat	146,826	132,060	155,127	151,870	146,904	148,493	171,239	130,828	131,616	118,569	106,867	147,340	1,687,739	193	1,688
47	LLH Energy Revenue Flat=(45*13)/1000	$2,504	$2,911	$3,223	$2,883	$2,453	$2,260	$2,435	$1,984	$1,160	$2,026	$2,120	$2,885	$28,844		
48	HLH Energy Revenue Flat=(46*14)/1000	$4,726	$4,534	$5,558	$4,620	$4,564	$4,280	$4,630	$2,955	$2,692	$2,986	$3,151	$4,486	$49,183		
49	GSP Demand	338	342	371	377	381	341	403	457	500	495	413	368	4,786		
50	Demand Revenue=(49*24)	$712	$769	$875	$755	$777	$648	$718	$677	$674	$822	$801	$735	$8,963		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2010**															
4																
5																
6														Fiscal Year 2010		
7	**Eastern HUB**	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total	aMW	GWh
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount													$0		
53	PF Other Energy													0	0	0
54	PF Block Other Revenue															
55																
56	**PF SLICE**	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$101,318		
57	Percent of SLICE	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	393	
58	Slice Rate	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050			
59	Slice Charges = 57*58*100	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$101,316		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues															
62																
63	**East Hub FPS (Pre-Subscription) Sales**															
64	LLH Energy Pre-Sub	48,150	59,384	72,881	73,553	59,687	56,954	49,899	52,140	49,789	66,215	53,930	49,608	692,190	79	692
65	LLH Energy Revenue	$1,034	$1,294	$1,611	$1,578	$1,279	$1,212	$944	$551	$468	$859	$945	$1,067	$12,842		
66	HLH Energy Pre-Sub	76,383	86,899	102,375	104,764	90,240	89,513	76,449	77,523	84,915	90,684	94,346	73,663	1,047,754	120	1,048
67	HLH Energy Revenue	$1,863	$2,141	$2,558	$2,537	$2,182	$2,104	$1,617	$1,005	$1,037	$1,421	$1,967	$1,746	$22,179		
68	GSP Demand	228	249	282	294	283	239	218	190	196	250	234	204	2,867		
69	Demand Revenue	$248	$280	$321	$317	$304	$253	$223	$185	$184	$253	$247	$214	$3,028		
70	Load Variance	121,878	140,024	167,495	170,513	142,979	140,719	122,647	124,789	126,347	152,275	143,382	120,441	1,673,489	191	1,673
71	Load Variance Revenue	$71	$81	$97	$99	$83	$82	$71	$73	$74	$89	$83	$70	$973		
72	Low Density Discount	-$150	-$181	-$215	-$224	-$191	-$179	-$138	-$81	-$82	-$122	-$154	-$151	-$1,867		
73	Wind Integration Service													$0		
74	Other Presubscription revenues													$0		
75	**Irrigation Mitigation**								$4,778	$5,852	$8,976	$8,801		$28,407		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,155	123,083	0	498,445	57	498
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,478	217,906	243,565	207,128	0	816,077	93	816
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,470	$1,682	$3,063	$3,291	$0	$9,506		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,508	$1,575	$2,884	$2,894	$0	$8,861		
80														$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$48,456	$53,355	$63,319	$56,619	$50,809	$46,302	$42,589	$36,627	$33,160	$46,045	$50,350	$48,388	$576,018		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	**Eastern HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8		$6,413	$7,798	$9,882	$8,527	$6,865	$5,954	$5,274	$4,063	$2,502	$5,330	$5,563	$7,268	$75,439		
9	East Hub PF Billing Determinants	$13,727	$15,526	$19,359	$16,612	$14,566	$12,968	$11,531	$8,395	$7,752	$10,461	$12,696	$13,508	$157,101		
10	**PF Full Service**	$2,853	$2,900	$3,582	$3,396	$3,176	$2,424	$2,159	$1,717	$1,601	$2,701	$2,776	$2,670	$31,956		
11	LLH Energy Flat	271,978	311,441	375,878	387,578	308,962	281,917	271,282	260,295	230,387	289,051	254,235	297,490	3,540,494	404	3,540
12	HLH Energy Flat	426,448	452,249	540,313	546,079	468,813	449,970	426,434	371,642	379,068	415,454	430,502	443,612	5,350,584	611	5,351
13	PF Flat LLH Energy Rate	$23.58	$25.04	$26.29	$22.00	$22.22	$21.12	$19.44	$15.61	$10.86	$18.44	$21.88	$24.43			
14	PF Flat HLH Energy Rate	$32.19	$34.33	$35.83	$30.42	$31.07	$28.82	$27.04	$22.59	$20.45	$25.18	$29.49	$30.45			
15	LLH Energy Revenue Flat= (11*13)/1000	$6,413	$7,798	$9,882	$8,527	$6,865	$5,954	$5,274	$4,063	$2,502	$5,330	$5,563	$7,268	$75,439		
16	HLH Energy Revenue Flat= (12*14)/1000	$13,727	$15,526	$19,359	$16,612	$14,566	$12,968	$11,531	$8,395	$7,752	$10,461	$12,695	$13,508	$157,101		
17	GSP Demand	1,352	1,289	1,518	1,698	1,557	1,276	1,213	1,160	1,186	1,627	1,431	1,335	16,642		
18	PF GSP Demand Rate	$2.11	$2.25	$2.36	$2.00	$2.04	$1.90	$1.78	$1.48	$1.35	$1.66	$1.94	$2.00			
19	Demand Revenue= (18*17)	$2,852	$2,900	$3,583	$3,396	$3,176	$2,423	$2,160	$1,717	$1,601	$2,701	$2,776	$2,670	$31,955		
20	PF Ld Variance	701,360	767,128	918,355	934,739	779,133	734,922	702,325	789,448	832,139	956,591	901,036	743,259	9,760,435	1,114	9,760
21	PF Ld Variance Rate	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51	$0.51			
22	Load Variance= (20*21)/1000	$357	$391	$468	$476	$397	$374	$358	$357	$358	$419	$398	$379	$4,733		
23	Low Density Discount Percent=28/(15+16+	-3.83%	-3.69%	-3.73%	-3.76%	-3.71%	-3.75%	-4.02%	-3.77%	-3.59%	-3.61%	-3.61%	-4.09%			
24	Low Density Discount	-$894	-$983	-$1,243	-$1,092	-$929	-$814	-$776	-$548	-$439	-$683	-$775	-$975	-$10,150		
25	LBCRAC True-up/Lookback Adjust													$0		
26	PF Other Energy													0	0	0
27	PF Other Revenues													$0		
28		$2,242	$2,626	$3,143	$2,723	$2,251	$2,059	$1,698	$1,348	$891	$1,873	$1,916	$2,260	$25,031		
29	**PF Partial Service**	$4,515	$5,119	$5,968	$5,123	$4,661	$4,346	$3,486	$2,689	$2,686	$3,531	$4,246	$4,005	$50,375		
30	LLH Energy Flat	95,095	104,855	119,550	123,767	101,324	97,506	87,331	86,378	82,066	101,563	87,591	92,521	1,179,547	135	1,180
31	HLH Energy Flat	140,261	149,117	166,571	168,424	150,005	150,787	128,923	119,016	131,357	140,222	143,975	131,523	1,720,181	196	1,720
32	LLH Energy Revenue Flat = 30*13/1000	$2,242	$2,626	$3,143	$2,723	$2,251	$2,059	$1,698	$1,348	$891	$1,873	$1,916	$2,260	$25,031		
33	HLH Energy Revenue Flat = 31*14/1000	$4,515	$5,119	$5,968	$5,123	$4,661	$4,346	$3,486	$2,689	$2,686	$3,531	$4,246	$4,005	$50,375		
34	GSP Demand	354	391	432	427	410	367	343	280	302	349	338	308	4,301		
35	Demand Revenue = 34*17	$747	$881	$1,020	$853	$835	$697	$610	$415	$408	$580	$655	$617	$8,318		
36	Load Variance	242,426	260,293	293,049	295,465	256,517	254,428	222,927	217,148	226,970	257,462	246,447	230,816	3,003,948	343	3,004
37	Load Variance = 36*21/1000	$124	$133	$149	$151	$131	$130	$114	$110	$115	$130	$125	$118	$1,528		
38	LBCRAC True-up/Lookback Adjust													$0		
39	Low Density Discount Percent= 56/(42+43+	-2.48%	-2.34%	-2.32%	-2.19%	-2.30%	-2.34%	-2.35%	-2.31%	-2.42%	-2.39%	-2.45%	-2.65%			
40	Low Density Discount	-$189	-$205	-$239	-$194	-$181	-$169	-$139	-$106	-$99	-$146	-$170	-$185	-$2,023		
41	PF Other Energy													0	0	0
42	PF Other Revenue	-$121	-$130	-$147	-$148	-$128	-$127	-$111	-$109	-$113	-$129	-$123	-$115	-$1,502		
43		$2,634	$2,770	$3,223	$2,883	$2,453	$2,260	$2,435	$1,984	$1,160	$2,172	$1,976	$2,885	$28,835		
44	**PF Block Service**	$4,549	$4,726	$5,558	$4,620	$4,564	$4,280	$4,630	$2,955	$2,692	$2,814	$3,343	$4,487	$49,218		
45	LLH Energy Flat	111,707	110,641	122,581	131,065	110,401	106,994	125,243	127,087	106,824	117,765	90,326	118,103	1,378,737	157	1,379
46	HLH Energy Flat	141,318	137,660	155,127	151,870	146,904	148,493	171,239	130,828	131,616	111,758	113,363	147,340	1,687,516	193	1,688
47	LLH Energy Revenue Flat=(45*13)/1000	$2,634	$2,770	$3,223	$2,883	$2,453	$2,260	$2,435	$1,984	$1,160	$2,172	$1,976	$2,885	$28,835		
48	HLH Energy Revenue Flat=(46*14)/1000	$4,549	$4,726	$5,558	$4,620	$4,564	$4,280	$4,630	$2,955	$2,692	$2,814	$3,343	$4,486	$49,218		
49	GSP Demand	338	342	371	377	381	341	403	457	500	495	413	368	4,786		
50	Demand Revenue=(49*24)	$712	$769	$875	$755	$777	$648	$718	$677	$674	$822	$801	$735	$8,963		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Revenues at Proposed Rates															
2	Revenue ($ Thousands)															
3	**Fiscal Year 2011**															
4																
5																
6														**Fiscal Year 2011**		
7	**Eastern HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount													$0		
53	PF Other Energy													0	0	0
54	PF Block Other Revenue															
55																
56	**PF SLICE**	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$101,318		
57	Percent of SLICE	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	4.1191%	388	
58	Slice Rate	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050	$2,050			
59	Slice Charges = 57*58*100	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$8,443	$101,318		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues															
62																
63	**East Hub FPS (Pre-Subscription) Sales**	-4.47%	-4.58%	-4.52%	-4.78%	-4.80%	-4.75%	-4.66%	-4.29%	-4.47%	-4.45%	-4.53%	-4.69%			
64	LLH Energy Pre-Sub	49,234	60,709	74,446	75,122	61,011	58,170	51,030	53,355	50,914	64,534	55,169	50,759	704,453	80	704
65	LLH Energy Revenue	$1,058	$1,323	$1,645	$1,613	$1,308	$1,239	$966	$564	$480	$837	$967	$1,092	$13,092		
66	HLH Energy Pre-Sub	78,091	88,823	104,576	106,996	92,240	91,460	78,155	79,299	86,808	96,178	96,440	75,323	1,074,389	123	1,074
67	HLH Energy Revenue	$1,621	$1,866	$2,246	$2,200	$1,896	$1,862	$1,412	$896	$921	$1,290	$1,705	$1,499	$19,414		
68	GSP Demand	232	253	287	300	287	243	222	194	199	253	238	208	2,916		
69	Demand Revenue	$251	$285	$325	$321	$309	$258	$227	$189	$188	$256	$252	$218	$3,078		
70	Load Variance	124,603	143,199	171,189	174,247	146,252	143,814	125,414	127,720	129,297	156,026	146,646	123,201	1,711,608	195	1,712
71	Load Variance Revenue	$72	$83	$100	$101	$85	$84	$73	$74	$75	$91	$85	$72	$996		
72	Low Density Discount	-$134	-$163	-$195	-$203	-$173	-$163	-$125	-$74	-$74	-$110	-$136	-$135	-$1,685		
73	Wind Integration Service													$0		
74	Other Presubscription revenues													$0		
75	**Irrigation Mitigation**								$4,778	$5,852	$8,946	$8,805		$28,381		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,485	122,864	0	498,556	57	499
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,478	217,906	242,148	207,416	0	814,948	93	815
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,470	$1,682	$3,060	$3,293	$0	$9,504		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,508	$1,575	$2,870	$2,894	$0	$8,847		
80		$0												$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$48,981	$54,158	$64,164	$57,162	$51,308	$46,751	$42,983	$37,018	$33,477	$46,610	$50,931	$48,844	$582,384		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1							Revenues at Proposed Rates									
2		-1					Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2010**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8																
9	**PF Residential Exchange**															
10	Demand (MW)	5934	6279	7966	9035	8729	6370	6195	4249	3585	4090	4833	5912	73176		
11	Demand Rate															
12	HLH Energy (MWhr)	1,785,050	2,030,470	2,615,292	2,888,823	2,710,153	2,532,966	2,287,625	1,516,228	1,262,057	1,226,669	1,633,037	2,006,469	24,494,840	2,796	24,495
13	LLH Energy (MWhr)	1,079,756	1,167,413	1,470,165	1,896,075	1,719,156	1,529,673	1,307,822	950,432	686,134	692,087	816,193	1,114,604	14,429,507	1,647	14,430
14	Residential Exchange Rate	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)	(49.15)		
15																
16	**Residential Exchange Revenue ($000) = (12+13)*14**	-$140,818	-$157,190	-$200,818	-$235,199	-$217,720	-$199,696	-$176,732	-$121,247	-$95,762	-$94,315	-$120,390	-$153,414	-$1,913,302		
17	LB CRAC True-up/Lookback adjustment													$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	IP LBCRAC True-up	17	17	17	17	17	17	17	17	17	17	17	17	204		
21	**PAC capacity, WNP-3 and other L-T contracts**	7,344	6,528	7,072	6,800	6,528	7,344	7,072	6,800	7,072	7,072	7,072	6,800	83,504	10	84
22	Demand (MW)	5,304	5,729	5,576	5,848	4,896	5,287	5,168	5,848	5,168	5,576	5,576	5,440	65,416	7	65
23	HLH Energy (MWhr)	$461	$513	$557	$499	$465	$489	$394	$354	$326	$416	$466	$477	$5,416		
24	LLH Energy (MWhr)													$0		
25	Energy (aMW)															
26	Revenue ($ Thousand)	751	863	770	770	770	688	688	888	670	685	838	658	9,039		
27		65,203	113,205	155,066	167,528	134,573	108,217	115,324	195,151	108,395	84,266	159,606	82,702	1,489,236	170	1,489
28	**Contractual Obligations (CER)**	-139,245	-60,973	-31,321	-44,290	-22,119	-57,999	-54,897	-4,886	-64,258	-56,596	-18,103	-102,265	-656,952	-75	-657
29	Demand (MW)	-100	72	166	166	167	68	84	256	61	37	190	-27	1,141	95	832
30	HLH Energy (MWhr)	$5,000	$11,295	$11,476	$11,476	$10,932	$8,278	$8,171	$8,871	$5,000	$5,000	$8,997	$5,000	$99,495		
31	LLH Energy (MWhr)															
32	Energy (aMW)															
33	Revenue ($ Thousand)	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,240	1,240	15,210		
34	0	422,490	408,312	421,922	421,922	381,091	421,922	407,745	421,922	408,312	421,922	392,088	379,440	4,909,088	560	4,909
35	Monthly Trading Floor Committed Sales (MWH)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Monthly Trading Floor Committed Sales ($000)	567	567	567	567	567	567	567	567	567	567	527	527	6,725	560	
37		0	0	0	0	0	0	0	0	0	0	0	0	$0		
38	Monthly Trading Floor Balancing Sales (MWH)															
39	Monthly Trading Floor Balancing Sales ($000)															
40																
41	Other Monthly Sales (MWH)															
42	Other Monthly Sales ($000)	423,798	310,926	472,529	1,221,617	1,013,607	1,279,887	1,731,862	2,929,925	2,243,394	1,733,918	560,047	359,765	14,281,275	1,630	14,281
43		$17,392	$13,389	$20,486	$59,405	$47,227	$56,460	$70,088	$108,059	$84,185	$78,127	$27,440	$17,479	$599,737		
44	FPS Bookouts															
45	Revenue reversals ($000)	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
46		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1							Revenues at Proposed Rates									
2		-1					Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2010**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
47	**Power Purchases**															
48	**ERE Augmentation Power purchases**															
49	**ERE Augmentation Purchase Expense**															
50	**IOU Power Buyback/Deferred LB CRAC expense**															
51	Expenses ($ Thousand)															
52		6,986	7,280	8,274	7,504	6,647	6,555	5,396	7,924	9,304	8,467	9,108	6,783	90,228	10	90
53	Renewable HLH (MWH)	$236	$255	$297	$237	$221	$203	$161	$200	$214	$230	$280	$224	$2,759		
54	Renewable LLH (MWH)															
55	Renewable Expense ($000) (included in Program Expense Forecast)													$0		
56																
57		26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,658	24,297	324,419	37	324
58	Power Purchases Bookouts (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,460	19,997	262,982	30	263
59	Power Purchases Reversals ($000)	$2,419	$2,434	$2,358	$2,250	$2,149	$3,453	$2,750	$2,869	$2,760	$2,764	$2,435	$2,318	$30,960		
60																
61	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624															
62	TOTAL HLH Completed: PRE 8/1/00 79620															
63	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
64	TOTAL LLH Completed: PRE 8/1/00 79621															
65		276,747	268,192	276,747	276,747	249,965	276,375	267,820	276,747	267,820	276,747	276,747	267,820	3,258,474	372	3,258
66	PURCHASE TOTAL HLH Completed: POST 8/1/00															
67	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
68	PURCHASE TOTAL LLH Completed: POST 8/1/00															
69	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
70		$14,763	$14,306	$14,763	$14,763	$13,334	$14,743	$14,287	$14,763	$14,287	$14,763	$14,763	$14,287	$173,821		
71																
72	Other Committed Power Purchases (MWH)															
73	Balancing Power Purchases (MWH)															
74	NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590															
75	Other Committed Purchase Power Expense ($000)															
76	Balancing Purchase Power Expense ($000)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
77	Trading Floor Purchase Power Expense ($000)	160,110	62,465	166,715	178,595	140,645	88,227	62,620	9,612	17,643	2,004	151,469	70,508	1,110,613	127	1,111
78																
79		$384	$390	$370	$439	$473	$145	$124	$175	$162	$117	$167	$118	$3,065		
80	Residential Exchange Power Purchase	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$7,856	$94,275		
81	Residential Exchange cost															
82																
83																
84	Residential Exchange Power Purchase	2,864,806	3,197,882	4,085,457	4,784,898	4,429,309	4,062,639	3,595,448	2,466,659	1,948,191	1,918,756	2,449,230	3,121,073	38,924,348	4,443	38,924
85	Residential Exchange cost	$159,426	$177,962	$227,356	$266,280	$246,491	$226,086	$200,087	$137,270	$108,417	$106,779	$136,300	$173,688	$2,166,140		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1							Revenues at Proposed Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2011**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8																
9	**PF Residential Exchange**															
10	Demand (MW)	5959	6301	7982	9027	8728	6373	6289	4344	3708	4235	4961	6017	73924		
11	Demand Rate															
12	HLH Energy (MWhr)	1,795,004	2,038,426	2,621,829	2,887,031	2,710,243	2,534,069	2,323,017	1,551,707	1,306,578	1,274,141	1,678,206	2,043,502	24,763,752	2,827	24,764
13	LLH Energy (MWhr)	1,087,169	1,173,296	1,475,108	1,895,779	1,720,058	1,531,300	1,330,001	974,378	713,191	721,860	842,186	1,137,525	14,601,852	1,667	14,602
14	Residential Exchange Rate	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)	(49.73)		
15																
16	**Residential Exchange Revenue ($000) = (12+13)*14**	-$143,324	-$159,711	-$203,731	-$237,838	-$220,308	-$202,161	-$181,656	-$125,616	-$100,438	-$99,256	-$125,333	-$158,185	($1,957,558)		
17	LB CRAC True-up/Lookback adjustment													$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	IP LBCRAC True-up	17	17	17	17	17	17	17	17	17	17	17	17	204		
21	**PAC capacity, WNP-3 and other L-T contracts**	7,072	6,800	7,072	6,800	6,528	7,344	7,072	6,800	7,072	6,800	7,344	6,800	83,504	10	84
22	Demand (MW)	5,576	5,457	5,576	5,848	4,896	5,287	5,168	5,848	5,168	5,848	5,304	5,440	65,416	7	65
23	HLH Energy (MWhr)	$460	$515	$557	$499	$465	$489	$394	$354	$326	$414	$468	$477	$5,417		
24	LLH Energy (MWhr)													$0		
25	Energy (aMW)															
26	Revenue ($ Thousand)	728	847	754	754	754	672	672	865	670	700	684	83	8,183		
27		59,783	112,399	151,706	163,848	131,373	104,696	111,874	190,401	108,395	83,906	92,670	1,571	1,312,622	150	1,313
28	**Contractual Obligations (CER)**	-129,557	-55,212	-23,232	-36,324	-15,390	-50,495	-49,437	-344	-64,258	-56,236	-76,903	-21,134	-578,522	-66	-579
29	Demand (MW)	-94	79	173	171	173	73	87	255	61	37	21	-27	1,010	84	734
30	HLH Energy (MWhr)	$5,000	$11,143	$11,325	$11,325	$10,781	$8,126	$8,019	$8,653	$5,000	$5,000	$5,406	$20	$89,796		
31	LLH Energy (MWhr)															
32	Energy (aMW)															
33	Revenue ($ Thousand)	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	14,880		
34	0	392,615	379,440	392,088	392,088	354,144	392,088	378,913	392,088	379,440	392,088	384,648	372,240	4,601,880	525	4,602
35	Monthly Trading Floor Committed Sales (MWH)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Monthly Trading Floor Committed Sales ($000)	524	524	524	524	524	524	524	524	524	524	524	524	6,288	525	
37		0	0	0	0	0	0	0	0	0	0	0	0	$0		
38	Monthly Trading Floor Balancing Sales (MWH)															
39	Monthly Trading Floor Balancing Sales ($000)															
40																
41	Other Monthly Sales (MWH)															
42	Other Monthly Sales ($000)	580,300	524,763	609,651	1,327,415	1,105,700	1,376,015	1,465,795	2,432,918	2,145,749	1,826,259	764,566	411,774	14,570,907	1,663	14,571
43		$27,298	$25,840	$30,663	$71,272	$57,856	$69,445	$67,239	$105,800	$89,507	$91,817	$41,206	$22,022	$699,967		
44	FPS Bookouts															
45	Revenue reversals ($000)	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
46		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1							Revenues at Proposed Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2011**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
47	**Power Purchases**															
48	**ERE Augmentation Power purchases**															
49	**ERE Augmentation Purchase Expense**															
50	**IOU Power Buyback/Deferred LB CRAC expense**															
51	Expenses ($ Thousand)															
52		5,311	5,533	6,284	5,702	5,056	4,986	4,106	5,532	6,225	6,264	6,885	5,129	67,014	8	67
53	Renewable HLH (MWH)	$179	$195	$226	$180	$168	$154	$123	$140	$143	$170	$212	$170	$2,061		
54	Renewable LLH (MWH)															
55	Renewable Expense ($000) (included in Program Expense Forecast)													$0		
56																
57		26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,659	24,297	324,420	37	324
58	Power Purchases Bookouts (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,459	19,997	262,981	30	263
59	Power Purchases Reversals ($000)	$2,452	$2,470	$2,391	$2,280	$2,175	$3,506	$2,788	$2,907	$2,798	$2,801	$2,467	$2,349	$31,384		
60																
61	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624															
62	TOTAL HLH Completed: PRE 8/1/00 79620															
63	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
64	TOTAL LLH Completed: PRE 8/1/00 79621															
65		445,636	431,860	445,636	445,636	402,510	445,037	431,261	445,636	431,261	445,636	445,636	431,261	5,247,005	599	5,247
66	PURCHASE TOTAL HLH Completed: POST 8/1/00															
67	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
68	PURCHASE TOTAL LLH Completed: POST 8/1/00															
69	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
70		$25,714	$24,919	$25,714	$25,714	$23,225	$25,679	$24,884	$25,714	$24,884	$25,714	$25,714	$24,884	$302,757		
71																
72	Other Committed Power Purchases (MWH)															
73	Balancing Power Purchases (MWH)															
74	NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590															
75	Other Committed Purchase Power Expense ($000)															
76	Balancing Purchase Power Expense ($000)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
77	Trading Floor Purchase Power Expense ($000)	52,945	37,139	111,049	134,257	114,924	78,016	104,280	32,455	45,273	1,054	103,329	70,508	885,228	101	885
78																
79		$54	$60	$40	$109	$143	$145	$124	$175	$162	$117	$167	$118	$1,415		
80	Residential Exchange Power Purchase	$2,905	$1,987	$6,091	$8,213	$7,005	$4,668	$5,681	$1,844	$2,583	$64	$6,470	$4,195	$51,706		
81	Residential Exchange cost															
82																
83																
84	Residential Exchange Power Purchase	2,882,173	3,211,722	4,096,937	4,782,810	4,430,300	4,065,369	3,653,017	2,526,085	2,019,769	1,996,001	2,520,392	3,181,028	39,365,605	4,494	39,366
85	Residential Exchange cost	$163,534	$182,233	$232,460	$271,377	$251,375	$230,669	$207,272	$143,330	$114,602	$113,253	$143,007	$180,492	$2,233,604		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ
1	Feb 9, 2009 @ 12:55						Revenues at Proposed Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2010**									
4																
5																
6															**Fiscal Year 2010**	
7		**Oct-09**	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Total**	**aMW**	**GWh**
8																
9	**Generation Inputs**															
10																
11	Generation Dropping	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$703		
12	Synchronous Condensor Operations	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$2,769		
13	Station Service	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$3,955		
14	Redispatch Service	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$400		
15	Within hour Balancing Service for Wind Integration	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$8,695	$104,343		
16	Operating Reserves	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$47,173		
17	Regulating Reserves	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$14,590		
18	BOR Network/Delivery Facilities	$543	$543	$543	$543	$543	$543	$543	$543	$543	$543	$543	$543	$6,518		
19	Generation Integration/Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
20	**Total Interbusiness Line**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$180,452**		
21																
22	**RESERVE SERVICES:**															
23	External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
24	Total External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
29	**TOTAL Ancillary and Reserves**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$15,038**	**$180,452**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$731	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$8,921		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,660	$5,660		
35	Misc. Generation	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,420		
36	Energy Efficiency Rev's	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$2,733	$2,733	$2,733	$20,500		
37	Green Tags and Green Premiums Bulk	$404	$378	$357	$320	$296	$589	$446	$489	$467	$477	$423	$394	$5,040		
38	Green Premium West	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	Green Premium East	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
40	4(h)(10)c credit	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$7,392	$88,705		
41	Network Wind Integration&Shaping	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$1,905		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$10,721**	**$10,674**	**$10,653**	**$10,617**	**$10,593**	**$10,889**	**$10,765**	**$10,837**	**$10,835**	**$12,229**	**$12,168**	**$17,771**	**$138,751**		
46																
47	**Trading Floor Transmission**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$7,039**	**$84,462**		
48	**Other Transmission Expenses**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$2,513**	**$30,159**		

Table 4.6.2 Summary of Revenues at Proposed Rates

	B	BK	BL	BM	BN	BO	BP	BQ	BR	BS	BT	BU	BV	BW	BX	BY
1	Feb 9, 2009 @ 12:55						Revenues at Current Rates									
2							Revenue ($ Thousands)									
3							**Fiscal Year 2011**									
4																
5																
6														**Fiscal Year 2011**		
7		**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Total**	**aMW**	**GWh**
8																
9	**Generation Inputs**															
10																
11	Generation Dropping	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$59	$703		
12	Synchronous Condensor Operations	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$231	$2,769		
13	Station Service	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$330	$3,955		
14	Redispatch Service	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$400		
15	Within hour Balancing Service for Wind Integration	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$11,664	$139,962		
16	Operating Reserves	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$3,931	$47,173		
17	Regulating Reserves	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$1,216	$14,590		
18	BOR Network/Delivery Facilities	$522	$522	$522	$522	$522	$522	$522	$522	$522	$522	$522	$522	$6,258		
19	Generation Integration/Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
20	**Total Interbusiness Line**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$215,811**		
21																
22	**RESERVE SERVICES:**															
23	External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
24	Total External	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
29	**TOTAL Ancillary and Reserves**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$17,984**	**$215,811**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$731	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$8,921		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
35	Misc. Generation	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,420		
36	Energy Efficiency Rev's	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$1,367	$2,733	$2,733	$2,733	$20,500		
37	Green Tags and Green Premiums Bulk	$404	$378	$357	$320	$296	$589	$446	$489	$467	$477	$423	$394	$5,040		
38	Green Premium West	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	Green Premium East	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
40	4(h)(10)c credit	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$7,498	$89,975		
41	Network Wind Integration&Shaping	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$159	$1,905		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$10,826**	**$10,780**	**$10,759**	**$10,722**	**$10,699**	**$10,995**	**$10,871**	**$10,942**	**$10,940**	**$12,335**	**$12,273**	**$12,217**	**$134,361**		
46																
47	**Trading Floor Transmission**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$6,861**	**$82,331**		
48	**Other Transmission Expenses**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$2,421**	**$29,049**		

Table 4.8.1 Secondary Sales

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2								**Surplus Sales FY 2010**						
3														
4		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Annual**
5														
6	**Monthly Hours**	744	721	744	744	672	743	720	744	720	744	744	720	**8,760**
7														
8	**Surplus Sales (aMW)**	570	431	635	1,642	1,508	1,723	2,405	3,938	3,116	2,331	753	500	**1,630**
9	**Secondary Revenue ($Thousand)**	17,392	13,389	20,486	59,405	47,227	56,460	70,088	108,059	84,185	78,127	27,440	17,479	**599,737**
10	**Average Sales Price ($/MWh)**	$ 41.04	$ 43.06	$ 43.35	$ 48.63	$ 46.59	$ 44.11	$ 40.47	$ 36.88	$ 37.53	$ 45.06	$ 49.00	$ 48.58	**$ 41.99**
11														
12								**Surplus Sales FY 2011**						
13														
14		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Ann Avg**
15														
16	**Monthly Hours**	744	721	744	744	672	743	720	744	720	744	744	720	**8,760**
17														
18	**Surplus Sales (aMW)**	780	728	819	1,784	1,645	1,852	2,036	3,270	2,980	2,455	1,028	572	**1,663**
19	**Secondary Revenue ($Thousand)**	27,298	25,840	30,663	71,272	57,856	69,445	67,239	105,800	89,507	91,817	41,206	22,022	**699,967**
20	**Average Sales Price ($/MWh)**	$ 47.04	$ 49.24	$ 50.30	$ 53.69	$ 52.32	$ 50.47	$ 45.87	$ 43.49	$ 41.71	$ 50.28	$ 53.90	$ 53.48	**$ 48.04**
21														

Table 4.8.2 Secondary Purchases

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
2								**Balancing Purchases FY 2010**						
3														
4		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Annual**
5														
6	**Monthly Hours**	744	721	744	744	672	743	720	744	720	744	744	720	**8,760**
7														
8	**Balancing Purchases (aMW)**	215	87	224	240	209	119	87	13	25	3	204	209	**136**
9	**Purchase Expenses ($Thousand)**	7,856	2,969	8,232	9,954	7,927	4,843	3,172	502	900	107	8,684	8,142	**63,288**
10	**Average Purchase Price ($/MWh)**	$ 49.07	$ 47.53	$ 49.38	$ 55.74	$ 56.36	$ 54.90	$ 50.65	$ 52.26	$ 51.04	$ 53.36	$ 57.33	$ 53.98	**$ 53.14**
11														
12								**Balancing Purchases FY 2011**						
13														
14		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Annual**
15														
16	**Monthly Hours**	744	721	744	744	672	743	720	744	720	744	744	720	**8,760**
17														
18	**Balancing Purchases (aMW)**	71	52	149	180	171	105	145	44	63	1	139	98	**101**
19	**Purchase Expenses ($Thousand)**	2,905	1,987	6,091	8,213	7,005	4,668	5,681	1,844	2,583	64	6,470	4,195	**51,706**
20	**Average Purchase Price ($/MWh)**	$ 54.87	$ 53.50	$ 54.85	$ 61.17	$ 60.95	$ 59.84	$ 54.48	$ 56.83	$ 57.05	$ 60.33	$ 62.61	$ 59.50	**$ 58.41**

Table 4.8.3 Augmentation Power Purchases

	A	B	C	D	E	F
2	**Augmentation Power Purchases**					
3						
4	Price = Weighted average annual purchase price for 1937 from 70 WY run.					
5		**FY**	**MW**	**Hours**	**$/MWh**	**Exp. ($ Thousand)**
6		**2010**	372	8,760	53.34	$ 173,821
7		**2011**	599	8,760	57.70	$ 302,757
8		**2012**	301	8,784	60.43	$ 159,868
9		**2013**	501	8,760	62.66	$ 274,762
10		**2014**	486	8,760	64.56	$ 274,959
11		**2015**	706	8,760	66.56	$ 411,560
12						
13					**Average**	**$ 266,288**

Table 4.10 Low Density Discount Revenue

	A	B	C	D	E	F	G
2	**Low Density Discount Revenue Example**						
3		Demand	Energy	Energy	Load Variance	Low Density Discount - non-slice	Calculated LDD
4		Full Day	HLH	LLH	Full Day	Full Day	(7% LDD)
5	200910	$25,552.10	$114,307.98	$54,515.07	$2,993.49	($13,815.80)	($13,815.80)
6	200911	$22,815.00	$135,386.54	$69,617.46	$3,430.28	($16,187.45)	($16,187.45)
7	200912	$28,225.60	$157,250.71	$90,973.92	$4,004.66	($19,631.84)	($19,631.84)
8	201001	$30,700.00	$145,650.96	$75,074.56	$4,182.87	($17,892.59)	($17,892.59)
9	201002	$28,050.00	$127,063.87	$62,457.76	$3,519.91	($15,476.41)	($15,476.41)
10	201003	$19,399.00	$114,791.21	$55,370.94	$3,369.70	($13,505.16)	($13,505.16)
11	201004	$18,405.20	$87,851.88	$44,914.17	$2,837.97	($10,780.65)	($10,780.65)
12	201005	$11,544.00	$72,016.92	$33,400.40	$2,718.82	($8,377.61)	($8,377.61)
13	201006	$11,137.50	$62,783.14	$19,478.50	$2,480.89	($6,711.60)	($6,711.60)
14	201007	$14,923.40	$74,895.40	$40,705.19	$2,644.26	($9,321.78)	($9,321.78)
15	201008	$15,384.20	$97,529.32	$40,978.61	$2,643.98	($10,957.53)	($10,957.53)
16	201009	$15,380.00	$88,426.80	$49,485.41	$2,517.23	($10,906.66)	($10,906.66)
17	201010	$25,931.90	$116,100.32	$55,377.16	$3,038.46	($14,031.35)	($14,031.35)
18	201011	$23,152.50	$137,320.00	$70,652.62	$3,481.89	($16,422.49)	($16,422.49)
19	201012	$28,650.40	$159,635.54	$92,353.62	$4,064.94	($19,929.32)	($19,929.32)
20	201101	$31,160.00	$147,841.20	$76,209.76	$4,245.80	($18,161.97)	($18,161.97)
21	201102	$28,478.40	$128,972.81	$63,353.66	$3,572.74	($15,706.43)	($15,706.43)
22	201103	$19,684.00	$116,534.24	$56,159.14	$3,420.27	($13,705.84)	($13,705.84)
23	201104	$18,690.00	$89,201.71	$45,623.34	$2,880.37	($10,947.68)	($10,947.68)
24	201105	$11,721.60	$73,101.24	$33,937.39	$2,759.64	($8,506.39)	($8,506.39)
25	201106	$11,299.50	$63,718.92	$19,775.63	$2,518.32	($6,811.87)	($6,811.87)
26	201107	$15,139.20	$78,964.48	$39,328.83	$2,687.80	($9,528.42)	($9,528.42)
27	201108	$15,617.00	$99,114.71	$41,573.75	$2,683.90	($11,129.26)	($11,129.26)
28	201109	$15,600.00	$89,766.60	$50,267.16	$2,555.11	($11,073.22)	($11,073.22)

APPENDIX A

7(C)(2) INDUSTRIAL MARGIN STUDY

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Appendix A

7(c)(2) Industrial Margin Study

1. INTRODUCTION

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to DSI customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region."

Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account

(1) the comparative size and character of the loads served;

(2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and

(3) direct and indirect overhead costs, all as related to the delivery of power to industrial customers.

2. PURPOSE

The purpose of this study is to describe the calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-07 energy charges. These adjusted PF-07 energy charges and Demand Charges are applied to the DSI billing determinants to determine the IP-07 rate.

3. METHODOLOGY

3.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

BPA applies the PF-07 demand and energy charges (before any 7(b)(2) or floor rate adjustments) to the forecasted DSI billing determinants.

3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA DSI delivery facilities. An overall margin is derived by weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

3.3 Margin Determination Factors

3.3.1 7(c)(2)(A) – Comparative Size and Character of the Loads Served. The data base used for the study includes utilities that serve at least one industrial customer with a peak demand of at least 3.5 MW.

3.3.2 7(c)(2)(B) – Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate allocated costs to the industrial customer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in BPA industrial margin calculation.

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile. Because the DSI contracts no longer include these provisions, BPA has not made this adjustment as part of this study.

3.3.3 7(c)(2)(C) – Direct and Indirect Overhead Costs. BPA relies on cost of service studies and other spreadsheets prepared by the public body and cooperative customers to incorporate the per unit overhead costs associated with service to large industrial customers.

4. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves two steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall margin. BPA DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

4.1 Data Base

The data base was collected from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial customers were deleted from the data base and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data were required to sign confidentiality agreements. All reported utility data reported has been identified by a randomly assigned number. This is essentiality the same way margin data was displayed in the 2002 industrial margin study. The data base consists of cost information from 30 utilities that have an industrial load of at least 3.5 MW. Attachment A displays each utility's percentage of total energy, its inflated and weighted individual margin, and the overall energy-weighted typical industrial margin for all utilities.

4.2 Utility Margins

The individual utility margins are based on categorical costs allocated by the utilities to their industrial customers. The categories of costs include production, transmission, distribution, revenue taxes, and other overhead costs. The data for each of the utilities in the study are included as Attachment B. The total dollar amounts assigned by the utility to each category, divided by the total kWh energy sales to the appropriate industrial class, yields a mills/kWh figure for that cost category. Various costs assigned to the "other" category are added to arrive at each utility's industrial margin.

4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The weighted industrial margin is 0.57 mills/kWh. This margin has been added to the PF-10 energy charges and applied to the forecasted DSI billing determinants.

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Revenue Tax	Weighted Margin
2	205,901,980	40.37	33.54	0.74	3.63	0.00	2.46	0.0000
6(a)	46,850,000	51.45	33.08	5.47	9.34	0.64	2.92	0.0024
6(b)	60,446,000	41.79	26.19	5.06	7.41	0.55	2.59	0.0026
6(c)	463,006,000	42.28	27.96	5.54	5.52	0.63	2.62	0.0230
6(d)	191,102,000	55.20	30.37	2.46	7.53	3.23	1.53	0.0486
9	642,300,490	49.36	46.08	0.08	0.34	0.00	2.85	0.0002
18	41,602,900	47.29	39.70	1.08	5.56	0.16	0.79	0.0005
24(a)	34,829,000					0.04		0.0001
24(b)	232,582,000					0.01		0.0002
24(c)	870,068,000					0.00		0.0002
24(d)	20,930,000					0.11		0.0002
27	122,921,925	37.30	36.82	0.38	0.04	0.06	0.01	0.0006
33(a)	404,177					1.00		0.0000
33(b)	46,768					0.98		0.0000
34(a)	883,847,000	35.67	18.31	3.24	12.26	1.08	0.78	0.0756
34(b)	647,043,000	40.00	18.31	3.24	16.60	1.08	0.78	0.0553
34(c)	1,142,044,000	32.96	19.34	3.19	8.37	1.28	0.78	0.1149
37	152,300,891	44.80	35.81	4.49	4.50	0.01	0.00	0.0001
38	57,980,000	26.05	24.58	0.02	0.16	0.00	1.30	0.0000
48	267,535,027	18.40	14.90	0.60	2.50	0.40	0.00	0.0084
49	135,521,839	71.76	42.93	20.15	5.55	0.00	3.12	0.0000
54	628,234		4.41	0.16	0.63	0.26	0.00	0.0000
56	42,095,000	53.60	50.15	0.04	1.94	0.33	1.15	0.0011
58	890,690,506	35.46	29.34	4.62	1.45	0.05	0.00	0.0032
64	401,856,000					0.18		0.0056
66	137,729,000	31.29	26.65	2.65	1.68	0.01	0.30	0.0001
69	29,114,880	43.02	34.59	2.37	3.63	0.00	2.43	0.0000
72	186,557,000	39.50	30.84	2.08	4.15	0.18	2.24	0.0026
86	75,723,640	34.25	23.26	5.47	3.13	0.15	2.25	0.0009
87	59,070,320					5.02		0.0234
93(a)	110,588,400					5.00		0.0436
93(b)	202,967,376					2.18		0.0349
93(c)	2,173,245,133					0.41		0.0709
93(d)	623,470,000					0.56		0.0275
97	176,302,116	53.11	40.80	6.15	5.16	0.04	0.96	0.0006
99	283,411,200					0.05		0.0011
103(a)	44,395,500	42.85	21.99	8.92	9.86	0.03	2.05	0.0001
103(b)	349,201,178					0.57		0.0158
104	16,490,000	50.99	31.79	4.47	11.25	0.04	3.45	0.0000
106	70,085,364	48.29	38.72	0.11	8.14	0.79	0.53	0.0044
113	487,626,018	38.75	30.99	2.73	5.03	0.00	0.00	0.0000
115	16,204,800	63.46	32.23	5.85	25.09	0.29	0.00	0.0004
122	87,307,518	46.60	36.26	0.51	8.57	0.64	0.64	0.0044
Total	**12,684,022,180**							**0.5735**

Utility Number: # 2	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$6,906,015	$6,906,015				
Taxes Assigned to Purchased Power	$418,062					$418,062
Fixed Operations Expense						
Supervisory Operating Expense	$133,780			$133,780		
Labor/O&M	$142,500			$142,500		
Distribution/Operations	$7,500			$7,500		
Distribution/Maintenance	$12,000			$12,000		
Transmission Lines/Maintenance	$1,000		$1,000			
General Plant/Maintenance and Misc. Op. Exp.	$620			$620		
Administrative Expense	$67,600		$227	$67,373		
Taxes on Operations Expense	$88,699					$88,699
Transmisson Capital Expenditures	$150,000		$150,000			
Reserve Funding						
C&R Discount account (books out below)	$42,000	$42,000				
Emergency Reserve	$50,000		$168	$49,832		
Debt Service	$339,777		$1,142	$338,635		
Incomes						
Other revenue	-$5,000		-$17	-$4,983		
Collection of C&R	-$42,000	-$42,000				
Annual MWh Sales **205,902**						
Mills/kWh	$40.37	33.54	0.74	3.63	0.00	2.46

Utility Number: # 6(a)	Total Industrial (C.1)	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$212,755	$212,755				
VAR (Generation)	$7,511	$7,511				
Purchased Power	$1,329,480	$1,329,480				
Transmission	$256,323		$256,323			
Distribution	$313,767			$436,091		
Customer Service, Accounts & Sales						
Meter reading	$443			$443		
Cust Records & Collection	$1,249			$1,249		
Low income	$25,004				$25,004	
Electric Marketing	$4,844				$4,844	
CILT on Retail Revenue (Contributions in Lieu of Taxes)	$137,028					$137,028
Secondary Cost of Service (customer facilities)	-$63	-$15	-$17	-$29	-$2	
Annual MWh Sales **46,850**						
Mills/kWh	51.45	33.08	5.47	9.34	0.64	2.93

Utility Number: # 6(b)	Total Industrial (D)	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$235,452	$235,452				
VAR (Generation)	$8,079	$8,079				
Purchased Power	$1,339,273	$1,339,273				
Transmission	$305,925		$305,925			
Distribution	$446,607			$446,607		
Customer Service, Accounts & Sales						
Meter reading	$295			$295		
Cust Records & Collection	$750			$750		
Low income	$28,546				$28,546	
Electric Marketing	$4,844				$4,844	
CILT on Retail Revenue (Contributions in Lieu of Taxes)	$156,436					$156,436
Secondary Cost of Service (customer facilities)	-$76	-$18	-$23	-$33	-$2	
Annual MWh Sales **60,446**						
Mills/kWh	41.79	26.19	5.06	7.41	0.55	2.59

Utility Number: # 6(c)	Total Industrial (A)	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$2,008,219	$2,008,219				
VAR (Generation)	$70,559	$70,559				
Purchased Power	$10,868,335	$10,868,335				
Transmission	$2,565,406		$2,565,406			
Distribution	$2,553,347			$2,553,347		
Customer Service, Accounts & Sales						
Meter reading	$886			$886		
Cust Records & Collection	$3,748			$3,748		
Low income	$221,368				$221,368	
Electric Marketing	$69,743				$69,743	
CILT on Retail Revenue (Contributions in Lieu of Taxes)	$1,213,126					$1,213,126
Annual MWh Sales **463,006**						
Mills/kWh	42.28	27.96	5.54	5.53	0.63	2.62

Utility Number: # 6(d)	Total Industrial (B)	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$5,803,760	$5,803,760				
Transmission	$470,366		$470,366			
Distribution	$1,439,075			$1,439,075		
CILT on Retail Revenue (Contributions in Lieu of Taxes	$291,685					$291,685
Other	$617,056				$617,056	
Annual MWh Sales 191,102						
Mills/kWh	45.12	30.37	2.46	7.53	3.23	1.53

Utility Number: # 9	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$15,092,617	$15,092,617				
Purchased Power	$14,986,318	$14,986,318				
Transmission						
Distribution	$151,655			$151,655		
Customer Accounts	$2,344				$2,344	
Administrative and General	$123,970	$122,709		$1,242	$19	
Taxes	$1,831,677					$1,831,677
Interest and Debt Service Expense	$449,470	$444,967		$4,503		
Capital Projects Funded From Rates						
Transmission	$51,699		$51,699			
Distribution	$57,312			$57,312		
General	$15,635			$15,635		
Other Direct Assignment	$10,557	$10,557				
Other Revenues	-$1,068,551	-$1,057,682	$0	-$10,703	-$165	
Annual MWh Sales **642,300**						
Mills/kWh	49.36	46.08	0.08	0.34	0.00	2.85

Utility Number: # 18	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,651,830	$1,651,830				
Transmission	$28,509		$28,509			
Distribution	$147,429			$147,429		
Customer	$8,652				$8,652	
G&A	$42,768		$6,605	$34,158	$2,005	
Depreciation	$56,047		$9,082	$46,965		
Taxes	$32,757					$32,757
Interest	$83,899		$13,595	$70,304		
Other Expenses	$23,337		$3,604	$18,639	$1,094	
Overcollection in prior years	-$70,516		-$10,891	-$56,320	-$3,305	
Other Operating Revenue	-$37,386		-$5,774	-$29,860	-$1,752	
Annual MWh Sales **41,603**						
Mills/kWh	47.28	39.71	1.08	5.56	0.16	0.79

Utility Number: # 24

Four industrial customers are sold power under special contracts. Customer 1 is charged a margin of $110/month; customers 2, 3, & 4 are charged $200/month.

Total energy sold Customer 1 34,829 MWh
Margin = $0.04/MWh

Total energy sold Customer 2 232,582 MWh
Margin = $0.01/MWh

Total energy sold Customer 3 870,068 MWh
Margin = $0.003/MWh

Total energy sold Customer 4 20,930 MWh
Margin = $0.12/MWh

Utility Number: # 27		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$4,525,439	$4,525,439				
Transmission		$30,213		$30,213			
Distribution		$3,114			$3,114		
Customer		$5,859				$5,859	
G&A		$51,689		$39,853	$4,108	$7,728	
Depreciation		$8,509		$7,714	$795		
Taxes		$1,202					$1,202
Interest		$2,348		$2,129	$219		
Other Expenses		$479		$369	$38	$72	
Overcollection in prior years		-$173		-$133	-$14	-$26	
Other Operating Revenue		-$43,292		-$33,379	-$3,440	-$6,473	
Annual MWh Sales	**122,922**						
Mills/kWh		37.30	36.82	0.38	0.04	0.06	0.01

Utility Number: # 33

Two industrial customers are sold power under a special contract. They are charged
a margin of 1.95 mills/kWh for power < 19.1 aMW, and 0.98 mills/kWh for power > 19.1 aMW.

Total energy sold Customer 1	404.2 MWh
Amount $0.98/MWh applied	394 MWh
Amount $1.95/MWh applied	9,098 MWh
Margin = 1.004	

Total energy sold Customer 2	46.8 MWh
Amount $0.98/MWh applied	0
Amount $1.95/MWh applied	46.8 MWh
Margin = 0.98	

Utility Number: # 34(a)	Large General Service: 1	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$5,095,753	$5,095,753				
Purchased Power	$9,942,842	$9,942,842				
Transmission	$2,859,810		$2,859,810			
Conservation	$1,501,264	$1,501,264				
Distribution	$11,357,022			$11,357,022		
Total Retail Service	$958,555				$958,555	
Network Adjustment	-$517,053			-$517,053		
Gradualism	-$358,410	-$358,410				
City General Fund Streetlight Bill	$686,122					$686,122
Annual MWh Sales 883,847						
Mills/kWh	35.67	18.31	3.24	12.27	1.09	0.78

Utility Number: # 34(b)	Large General Service: 2	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$3,730,478	$3,730,478				
Purchased Power	$7,278,915	$7,278,915				
Transmission	$2,093,598		$2,093,598			
Conservation	$1,099,040	$1,099,040				
Distribution	$8,314,203			$8,314,203		
Total Retail Service	$701,735				$701,735	
Network Adjustment	$2,425,211			$2,425,211		
Gradualism	-$262,383	-$262,383				
City General Fund Streetlight Bill	$502,293					$502,293
Annual MWh Sales **647,043**						
Mills/kWh	40.00	18.31	3.24	16.60	1.09	0.78

Utility Number: # 34(c)	Large General Service: 3	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$6,494,353	$6,494,353				
Purchased Power	$12,671,793	$12,671,793				
Transmission	$3,644,724		$3,644,724			
Conservation	$1,913,307	$1,913,307				
Distribution	$8,314,203			$8,314,203		
Total Retail Service	$1,457,105				$1,457,105	
Network Adjustment	-$616,205			-$616,205		
Gradualism	$1,012,668	$1,012,668				
City General Fund Streetlight Bill	$886,558					$886,558
Annual MWh Sales **1,142,044**						
Mills/kWh	32.96	19.34	3.19	8.37	1.28	0.78

Utility Number: # 37	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Generation	$3,152,494	$3,152,494				
Purchased Power	$2,095,522	$2,095,522				
Transmission	$642,044		$642,044			
Distribution	$642,766			$642,766		
Customer Accounts	$1,192				$1,192	
Administrative and General	$289,393	$205,545	$41,862	$41,909	$78	
Annual MWh Sales **152,301**						
Mills/kWh	44.80	35.81	4.49	4.50	0.01	0.00

Utility Number: # 38	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,111,817	$1,111,817				
Generation	$142,231	$142,231				
Transmission	$2,333		$2,333			
Distribution	$19,462			$19,462		
Customer Service, Accounts & Sales						
Mun Ser Tran Meter Read	$1,435			$1,435		
Mun Ser Tran Credit Bill	$77				$77	
Administrative and General						
Salaries & Benefits	$11,531	$9,907	$163	$1,456	$5	
Property Insurance	$12,661	$10,878	$178	$1,598	$6	
Outside Services	$34,986	$30,060	$493	$4,417	$16	
Maint of General Plant	$3,862	$3,349	$55	$458		
Warehouse	$4,093	$3,517	$58	$517	$2	
Engineering	$7,956	$6,836	$112	$1,004	$4	
Energy Services	$6,332	$5,440	$89	$799	$3	
Energy Services - Conservation	$8,802	$7,563	$124	$1,111	$4	
Misc General Expense	$6,620	$5,688	$93	$836	$3	
Debt Service Expense	$249,489	$249,489				
Transfers						
Return on Original Investment	$14,652	$12,589	$206	$1,850	$7	
Payments in Lieu of Taxes	$75,264					$75,264
Net Capital Improvement Projects from Rates	$77,012	$66,169	$1,085	$9,722	$36	
Less:						
Revenues (not from rates)	$279,952	$240,536	$3,945	$35,340	$130	
Annual MWh Sales **57,980**						
Mills/kWh	26.06	24.58	0.02	0.16	0.00	1.30

Utility Number: # 48 (in mills/kWh)	Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Expenses						
Generated Power	$0.0239	$0.0239				
Revenues from Resale of Gen. Power	-$0.0090	-$0.0090				
Transmission	$0.0006		$0.0006			
Distribution	$0.0025			$0.0025		
Other	$0.0004				$0.0004	
Annual MWh Sales **267,535**						
Mills/kWh	18.40	14.90	0.60	2.50	0.40	0.00

Utility Number: # 49	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$6,110,426	$6,110,426				
Sales from resale	-$292,173	-$292,173				
Transmission	$878,490		$878,490			
Distribution	$121,417			$121,417		
Customer Service, Accounts & Sales						
Meter Reading	$403			$403		
Cust. Records & Collection	$977			$977		
Info. & Insert Advertising	$101				$101	
Broadband	$1,306,623		$1,146,263	$160,227	$132	
Taxes	$423,071					$423,071
Debt Service	$574,049		$503,597	$70,394	$58	
Capital Improvements from Rates						
Transmission	$11,076		$11,076			
Substations	$75,240			$75,240		
Underground	$56,118			$56,118		
Vehicles	$4,763		$4,179	$584		
Customer - Dist Additions	$159,310			$159,310		
Customer - Transformers	$81,607			$81,607		
Customer - Meters & AMR	$192			$192		
Broadband	$33,143		$29,075	$4,064	$3	
Buildings	$3,314		$2,907	$406		
Improvements System	$203,258		$178,312	$24,925	$21	
Improvements General	$18,646		$16,358	$2,286	$2	
Administrative and General	$160,881		$141,136	$19,728	$16	
Less: Misc. Revenues						
Late Charges	-$75				-$75	
Misc. Service	-$85		-$74	-$10		
Rent from Electric Property	-$11,803		-$10,354	-$1,447	-$1	
Broadband Revenue	-$7,235		-$6,347	-$887	-$1	
Interest Income	-$89		-$78	-$11		
Misc. Non Operating Rev.	-$851		-$747	-$104		
Less: Outside Funding Sources	-$186,074		-$163,237	-$22,818	-$19	
Annual MWh Sales **135,522**						
Mills/kWh	71.76	42.93	20.15	5.55	0.00	3.12

Utility Number: # 54	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Transmission	$51,747		$51,747			
Distribution	$202,727			$202,727		
Customer Service						
Customer Accounts	$7,328				$7,328	
Conservation	$1,407,194	$1,407,194				
Sales	$107,882				$107,882	
Debt Service	$619,553	$524,672	$19,294	$75,587		
Capital Improvements recovered in rates	$354,190	$299,948	$11,030	$43,212		
Administrative and General	$930,036	$736,540	$27,085	$106,109	$60,302	
Annual MWh Sales **628,234**						
Mills/kWh	5.46	4.41	0.16	0.64	0.26	0.00

Utility Number: # 56	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,387,888	$1,387,888				
Generated Power	$586,037	$586,037				
Transmission	$1,320		$1,320			
Distribution	$71,299			$71,299		
Consumer Accounts	$263				$263	
Public Relations & Info	$11,873				$11,873	
Energy Services (Conservation)	$46,696	$46,696				
Administration & General	$63,036	$55,590	$116	$6,264	$1,066	
Tax (franchise)	$24,352					$24,352
Tax (property)	$24,044					$24,044
Capital Budget	$94,009	$82,904	$173	$9,342	$1,590	
less Financing from Reserves	-$38,189	-$33,678	-$70	-$3,795	-$646	
Reserve Funding	$31,767	$28,014	$58	$3,157	$537	
"Spread Net Revenue to Others"	-$48,279	-$42,576	-$89	-$4,798	-$817	
Annual MWh Sales **42,095**						
Mills/kWh	53.60	50.15	0.04	1.94	0.33	1.15

Utility Number: # 58		Total Industrial (C.1)	Production	Transmission	Distribution	Other	Revenue taxes
Production		$52,260,139	$52,260,139				
Transmission		$8,238,211		$8,238,211			
Distribution		$2,588,187			$2,588,187		
Customer Bill-Related Exp.		$80,587				$80,587	
Customer Service		$10				$10	
Annual MWh Sales	890,691						
Mills/kWh		35.46	29.34	4.63	1.45	0.05	0.00

Utility Number: # 64
Single industrial customer, rates set through contract. Margin over Wholesale Cost of Power is $5,870/mo. Total Industrial sales in 2004: 401,856 MWh Margin = 0.175

Utility Number: # 66		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$3,670,353	$3,670,353				
Transmission		$364,827		$364,827			
Demand		$227,092			$227,092		
Customer							
Actual		$521				$521	
Accounting		$984				$984	
Meters & Services		$4,582			$4,582		
Revenue Related		$41,037					$41,037
Annual MWh Sales	**137,729**						
Mills/kWh		31.29	26.65	2.65	1.68	0.01	0.30

Utility Number: # 69	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,035,622	$1,035,622				
Transmission	$712		$712			
Distribution	$59,107			$59,107		
Customer Service, Accounts & Sales						
Supervision	$12				$12	
Meter Reading	$18			$18		
Customer Records Collection	$54			$54		
Uncollectable Accounts	$4				$4	
Misc. Customer Accounts	$12				$12	
Customer Communication & Education	$9				$9	
Customer Assistance	$49				$49	
Advertising	$1				$1	
Administrative & General	$41,855		$497	$41,297	$61	
Total Interest/Debt Service Expense	$46,721		$556	$46,165		
Capital Projects Funded from Rates						
Production						
Transmission	$67,619		$67,619			
General	$18,698		$222	$18,476		
Other (Increases in inventory)	$2,281		$27	$2,254		
Taxes						
State Utility Tax	$45,972					
FICA	$3,966		$47	$3,913	$6	45,972
State Privelege Tax	$24,261					24,261
Other Taxes	$652					652
Incomes:						
Other Contributions						
Construction Fund Transfer	-$36,498		-$434	-$36,064		
Other Fund Transfers	-$7,756		-$92	-$7,653	-$11	
Other Contributions	-$19,618		-$233	-$19,357	-$28	
Other Revenues	-$2,655		-$32	-$2,620	-$4	
BPA C&R Credit	-$14,355	-$14,355				
Conservation Augmentation Reimbursement	-$14,221	-$14,221				
Annual MWh Sales **29,115**						
Mills/kWh	43.02	34.59	2.37	3.63	0.00	2.44

Utility Number: # 72		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Power		$5,754,034	$5,754,034				
Transmission		$388,142		$388,142			
Distribution		$774,768			$774,768		
Customer Related		$33,610				$33,610	
Revenue Taxes		$418,166					$418,166
Annual MWh Sales	**186,557**						
Mills/kWh		39.50	30.84	2.08	4.15	0.18	2.24

Utility Number: # 86	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Power	$1,758,827	$1,758,827				
Transmission	$257,503		$257,503			
Distribution	$87,087			$87,087	$12	
Customer Service, Accounts & Sales						
Supervision	$320				$320	
Meter Reading	$3,151			$3,151		
Customer Service	$4,064				$4,064	
Cashiering	$2,405				$2,405	
Cash: over/short	$1				$1	
Customer Accounts	$29,000			$29,000		
Delinquency Reporting	$760				$760	
Mail - PUD	$129				$129	
Billing	$724				$724	
Product & Service						
Substn. Maint. & Repair Service Exp.	$253			$ 253		
Mail Service Exp.	$428	$ -	$ 286	$ 133	$ 9	
Mail Service Postage	$3,258	$ -	$ 2,178	$ 1,009	$ 71	
Total Non-Operating Expense	$3,939					
Public Purpose - Supervision	$520				$ 520	
Administrative & General Expense	$101,505	$ -	$ 67,865	$ 31,425	$ 2,215	
Debt Service						
Distribution	$609			$ 609		
General Plant	$356			$ 356		
4/5 Settlement (will check out)	$124,423	$ -	$ 85,043	$ 39,380		
Generation Plant	$2,225	$ 2,225				
Substations	$487			$ 487		
Taxes	$170,130					$ 170,130
Rate-Financed Capital Expenditures						
Generation	$197	$ 197				
Distribution	$22,010			$22,010		
General Plant	$21,383			$ 21,383		
Capitalized Interest and A&G	$1,532	$ -	$ 1,024	$ 474	$ 33	
Annual MWh Sales 75,724						
Mills/kWh	34.24	23.26	5.47	3.13	0.15	2.25

Utility Number: # 87

Two industrial customers are sold power under special contracts. Each is charged a different margin.

Total energy sold Customer 1	39,018 MWh
Margin = $5.04/MWh	
Total energy sold Customer 2	20,053 MWh
Margin = $4.49/Mh	

Utility Number: # 93
Four industrial customers are sold power under special contracts. Each is charged a different margin. Total energy sold Customer 1 110,588 MWh Margin = $5.00/MWh Total energy sold Customer 2 202,967 MWh Margin = $2.18/Mh Total energy sold Customer 3 2,173,245 MWh Margin = $0.41/MWh Total energy sold Customer 4 623,470 MWh Margin = $0.56/Mh

Utility Number: # 97	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$7,193,153	$7,193,153				
Transmission	$538,019		$538,019			
Distribution	$332,877			$332,877		
Customer Accounts	$5,427				$5,427	
Customer Service	$527				$527	
Administrative and General	$360,927		$221,458	$137,018	$2,451	
Depreciation and Amortization						
Generation	$658	$658				
Transmission	$57,079		$57,079			
Distribution	$274,219			$274,219		
General	$42,588		$26,310	$16,278		
Amortization	$38,239		$23,623	$14,616		
Tax Expense						
Property	$9,656					$9,656
US Unemployment, FICA, State Unemployment, Workers Comp	$30,715		$18,846	$11,660	$209	
Gross Revenue Tax	$160,277					$160,277
Interest Expense						
Long Term Debt	$437,998		$270,585	$167,413		
Non Operating Margin	-$15,610		-$9,578	-$5,926	-$106	
Miscellaneous Revenues	-$102,599		-$62,953	-$38,950	-$697	
Annual MWh Sales **176,302**						
Mills/kWh	53.11	40.80	6.15	5.16	0.04	0.96

Utility Number: # 99

Three large industrial customers are sold power under a special tariff schedule. Each customer is charged a margin of $387/month.

Total annual MWh sales = 283,411 MWh.
Margin = $0.049/Mh

Utility Number: # 103 (a)	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$837,167	$837,167				
Generation	$37,352	$37,352				
Transmission	$106,309		$106,309			
Distribution	$117,563			$117,563		
Customer Service, Accounts and Sales	$808				$808	
Administrative and General	$130,160	$18,554	$52,807	$58,397	$401	
Taxes	$91,042					$91,042
Interest/Debt Service Expense	$202,147	$28,905	$82,267	$90,976		
Capital Project Funded from Rates (Power Production)	$369,640	$52,854	$150,431	$166,355		
Other Contributions	$70,923	$10,110	$28,774	$31,820	$219	
Less: **Other Revenues**	-$60,905	-$8,682	-$24,710	-$27,326	-$188	
Annual MWh Sales 44,396						
Mills/kWh	42.85	21.99	8.92	9.86	0.03	2.05

Utility Number: # 103(b)
Two large industrial customers are sold power under special contracts. Each customer is charged a margin of $100,000. Total annual MWh sales = 349,201 MWh. Margin = $0.57/Mh

Utility Number: # 104		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$524,167	$524,167				
Transmission		$73,054		$73,054			
Demand		$149,480			$149,480		
Distribution		$34,158			$34,158		
Customer Related		$595				$595	
Revenue Related		$56,858					$56,858
Direct Assignment		$2,571	$0	$730	$1,835	$6	
Annual MWh Sales	**16,490**						
Mills/kWh		50.99	31.79	4.47	11.25	0.04	3.45

Utility Number: # 106	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$2,713,692	$2,713,692				
Distribution	$261,858			$261,858		
Customer Service						
Meter Reading	$958			$958		
Customer Records & Collections	$2,724			$2,724		
Energy Services *(Conservation)*	$38,008				$38,008	
Ruralite & Customer Info	$1,091				$1,091	
Sales	$361				$361	
Supervision	$2,209			$1,923	$286	
Administrative and General	$122,505			$106,656	$15,849	
Tax	$37,144					$37,144
Depreciation						
Transmission	$7,999		$7,999			
Distribution	$76,949			$76,949		
General	$16,869			$16,869		
Total Depreciation	$101,817					
Interest Expense	$102,040			$102,040		
Other Expense	$314			$273	$41	
Annual MWh Sales **70,085**						
Mills/kWh	48.29	38.72	0.11	8.14	0.79	0.53

Utility Number: # 113	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$14,885,596	$ 14,885,596				
Generated Power	$242,706	$ 242,706				
Transmission	$1,444,368		$1,444,368			
Distribution	$1,862,469			$ 1,862,469		
Customer (meters, billing)	**$800.102**			$800,102		
Contract credits	-$340,987	-$19,027	-$113,230	-$208,730		
Annual MWh Sales 487,626						
Mills/kWh	38.75	30.99	2.73	5.03	0.00	0.00

Utility Number: # 115		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$522,295	$522,295				
Transmission		$94,834		$94,834			
Distribution		$406,659			$406,659		
Customer		$4,633				$4,633	
Annual MWh Sales	**16,205**						
Mills/kWh		63.46	32.23	5.85	25.10	0.29	0.00

Utility Number: # 122		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$3,165,390	$3,165,390				
Transmission		$14,347		$14,347			
Distribution		$242,525			$242,525		
Customer		$26,960				$26,960	
G&A		$278,509		$14,078	$237,977	$26,454	
Depreciation		$135,397		$7,562	$127,835		
Taxes		$55,528					$55,528
Interest		$128,225		$7,162	$121,063		
Other		$8,629		$436	$7,373	$820	
Under Collection		$49,377		$2,496	$42,191	$4,690	
Annual MWh Sales	**87,308**						
Mills/kWh		46.60	36.26	0.51	8.57	0.64	0.64

APPENDIX B

Letter from Mike Weedall

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

ENERGY EFFICIENCY

June 28, 2005

In reply refer to: PN-1

Dear Interested Party:

You will find attached the Bonneville Power Administration's (BPA) Final Post-2006 Conservation Program Structure.

BPA initiated a collaborative conservation planning process last September to solicit recommendations for our post-2006 conservation program structure (i.e., the FYs 2007-09 rate period). Based on the recommendations from the Conservation Workgroup, BPA issued its proposal for a 30-day public review and comment period on March 28, 2005. BPA received over 50 comment letters on the proposal, and we appreciate the many very thoughtful and constructive suggestions for improving the proposed program.

We have reviewed and considered these comments in preparing the attached Final Post-2006 Conservation Program Structure. The first document is a summary of the key issues raised in the comment letters and BPA's final decision on those key issues. The second document is a more detailed description of the final program structure.

This is a major step in designing our future conservation programs. However, the work is not finished. There is a Conservation Workgroup Phase 2 Committee with nine very experienced utility representatives acting as a sounding board for BPA in establishing the incentive levels BPA will pay for cost-effective measures under this final program structure. This is a simplified approach for structuring the list of cost-effective measures that will be easier to implement, and will include the appropriate level of oversight, utility verification and measurement of savings. BPA's desire is to be clear about how customers can receive their reimbursements under BPA's new programs. It is not our intent to dictate to customers how they should design and run their conservation programs. Again, BPA appreciates the dedication and hard work of the Phase 2 Committee.

BPA representatives will be happy to meet with power sales customers, utility groups or stakeholder organizations to discuss the decisions related to our Final Post-2006 Conservation Program. Please contact Becky Clark at 503-230-3158 to make the necessary arrangements.

Sincerely,

Mike Weedall
Energy Efficiency Vice President

Enclosures 2:
Summary of Key Issues Raised in Public Comment Process
Final Post-2006 Conservation Program Structure

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APPENDIX C
Post-2006 Key Issues

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Energy Efficiency
Bonneville Power Administration

Final Post-2006 Conservation Program Structure

Summary of Key Issues Raised in Public Comment Process

At the suggestion of Bonneville Power Administration (BPA), a Post-2006 Conservation Workgroup composed of over 65 utility representatives and conservation stakeholders was formed in the fall of 2004. This group met frequently to discuss new and existing approaches to BPA's conservation program for the post-2006 period. In January 2005, this group provided BPA recommendations and comments to help design the proposal that BPA distributed for public comment.

BPA issued its Post-2006 Conservation Program Structure Proposal for a 30-day public review and comment period on March 28, 2005. The close of comment period ended April 28, 2005. BPA received 56 comment letters and e-mails. Comments received are important to BPA and help provide guidance to improve upon BPA's and the region's efforts to develop conservation and energy efficiency.

After the brief program overview presented below, this document provides a statement of what was proposed for each key issue raised during the public comment period, a summary of the comments received on that topic, and BPA's response and evaluation for each issue. Again BPA appreciates the efforts of those parties taking the time to review the proposal. BPA has taken care to provide clarification of its program elements in response to any and all concerns raised in comments BPA received.

Program Overview

The portfolio of energy efficiency programs BPA will be offering for the post-2006 period is very similar to what is currently available. The key features of the final program are as follows:

1. a **conservation rate credit (CRC)** program (patterned after the current C&RD);
2. a **bilateral contracts program** for utility and federal agency customers (similar to the current ConAug program);
3. a **third-party contracts program** for cost-efficient, region-wide approaches (similar to the VendingMi$er program and includes support market transformation via the Northwest Energy Efficiency Alliance ((NEEA)));
4. support for critical **infrastructure** elements, including program evaluations to assure programs are achieving their intended targets;
5. a separately funded renewable resource option; and
6. a spending amount of **$80 million/year** intended to achieve BPA's 52 aMW/year share of the Northwest Power and Conservation Council's (Council) regional cost-effective conservation target at a weighted average cost of **$1.5 million/aMW**.

Key Issues: What was Proposed, Comment Summary, Evaluation and Final Decision

aMW Target Gap Proposal: Based upon the Northwest Power and Conservation Council's (Council) Fifth Power Plan, there is a regional conservation target over the 2007-11 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA proposed that it is reasonable to adjust the amount of its target to take into account the amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). As a result, BPA proposed to pursue a 52 aMW/year conservation target for the total of 260 aMW over the 2007-11 period.

BPA's existing and proposed conservation program structure is not focused on a centralized conservation acquisition program. To the contrary, most BPA programs are structured to provide funding support to BPA's customers and others to pursue and achieve regional conservation. Consequently, BPA proposed to include any and all of the conservation that is achieved and attributed to BPA's funding mechanisms toward the 52 aMW annual target, including the conservation achieved by investor owned utilities (IOUs) under the rate credit program and the conservation accomplished by BPA funding support for NEEA.

Summary of Comments Received: Some comments suggested that BPA should not reduce its share of the regional conservation target for "naturally occurring" conservation *(NEEC; NWEC; SCL)*; others agreed with this reduction *(Benton REA; PPC)*. Some comments stated that the target was too low and that BPA should consider the IOU exchange load as part of the calculation for determining BPA's share of the regional conservation target *(Council; NEEC; NWEC; PSE; WCTED)*. Others agreed that BPA should count the IOU conservation accomplished with BPA funds, even though BPA is not responsible for the IOU conservation *(Benton REA; PPC)*. Another comment suggested that BPA should be responsible for only 38 percent of the regional conservation (rather than rounding to 40 percent) *(Inland)*. Another concern that was raised related to the "gap" between the Council's five-year Action Plan (2005-09) and BPA's planned conservation horizon from 2007-11 *(Council; NWEC)*. They felt that there was a "gap" in 2005 and 2006 between BPA's current targets and the new ones and that it would be very difficult for BPA to "close the gap" with the proposed funding levels for 2007-09. One commenter indicated that the aMW target was too high and that more residential measures were needed *(Benton PUD)*.

Evaluation and Final Decision: With conservation being the least-cost resource for the region, BPA is aware that achieving the targets set by the Council are important to the region as a whole. Determining a reasonable percentage of the region's conservation target requires BPA to consider several factors, such as load and conservation that is naturally occurring. A factor that BPA believes is reasonable to reconsider, as expressed in comments above, is the duration of the planning horizon. As proposed, BPA is committed to achieving the 52 aMW/year conservation target. BPA will work toward this amount for the 2005-09 period, rather than the proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY

2006. BPA will seek to acquire an additional 16 aMW on top of the 220 aMW target by the end of 2006 in order to be on track to meet the new target of 52 aMW/year (see table below).

	Average Annual Target
New target for 2005 and 2006	52 aMW/year
Old target for 2005 and 2006	44 aMW/year
Additional aMW BPA will acquire to close gap between the old and new targets for 2005 and 2006	8 aMW/year X 2 years = **16 aMW**

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target.

Budget Proposal: BPA's proposed annual budget (capital and expense) for achieving the target of 52 aMW/year was $75 million. For the 2007-2009 rate period, the conservation rate credit (CRC) would be $0.0005/kWh (1/2 mill) on utility-purchased firm power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly $42 million. It is anticipated that $6 million per year out of the $42 million will be spent on renewable resource-related initiatives. BPA proposed paying an average of approximately $1.4M/aMW (which includes some administration allowance and infrastructure support costs) across the entire portfolio of programs.

Summary of Comments Received: Many commenters suggested that the budget was too low *(Council; EPUD; EWEB; Faste; Franklin PUD; Interfaith GWC; ODOE; NEEC; NWEC; SCL; WCTED)* with some proposing a budget increase of $25 to $35 M/year to achieve the higher targets *(Council; EPUD; NEEC; NWEC).* They indicated that it will cost closer to $1.8 to $1.9 M/aMW and not the $1.4 M/aMW that BPA proposed. Several comments recommended that BPA establish a "backstop" funding mechanism or contingency plan in case the proposed budget was insufficient to capture the new targets *(Benton PUD; Council; EWEB; NWEC; WCTED).* Some comments recommended that more funds are needed for infrastructure support and to address inflation *(SCL; NWEC).* One comment suggested that the budget was sufficient as proposed *(SUB).*

Evaluation and Final Decision: The fundamental question for BPA is what is the minimum spending level that will produce the targeted conservation savings level. Based on the comments received and further assessment, the spending level should be increased by $5M/year. This will provide $80M/year to capture the 52 aMW/year target. A majority of the comments received on this issue expressed support for this amount of funding. This increased amount of funding will provide customers and the region greater program flexibility at an average cost of $1.54M/aMW across the entire portfolio of programs, including the administrative cost allowances and infrastructure support (see Table 1). BPA believes these additional funds will facilitate achieving the Council's new targets by providing utilities a reasonable level of administrative allowance for the rate credit and the bilateral contract programs and more funds for incentives across the program portfolio BPA will be offering.

Table 1: Final Conservation Program Annual aMW Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year)+	20	$36M	$1.8M
Utility & Fed. Agency Bilateral Contracts+	17	$26M	$1.5M
Third-Party Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$80M	$1.5M

+ - includes a 15 percent administrative cost allowance.
* - assumes $6M/year of the $42M/year from a separate renewables budget will be spent on renewables.

<u>Administrative Allowance Proposal</u>: BPA proposed to include up to 10 percent administrative costs in the rate credit and bilateral contracts programs. Small utilities (7.5 aMW and under) would be allowed up 20 percent for administrative costs, provided they pursue cost-effective measures (or renewables) with the remaining 80 percent.

Summary of Comments Received: Many of the comments stated that allowing 10 percent for administrative costs under the rate credit was too low *(Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; PPC; PNGC; Richland; SCL; SUB; Umatilla; Whatcom).* It was suggested that 20 percent was more realistic given the new oversight and reporting requirements under the proposed rate credit program *(Canby; Cowlitz; EPUD; Idaho Falls; Okanogan; Pacific; PPC; PNGC; SCL; SUB).* One commenter thought 10 percent was too low and 20 percent was too high *(Inland).* A few commenters appreciated BPA including the up to 10 percent administrative costs under the bilateral contracts program *(Cowlitz; Lincoln Electric; PPC).*

Evaluation and Final Decision: BPA understands the concerns expressed in many comments regarding the administrative costs associated with implementing the new programs. BPA recognizes that many customers view a successful conservation program to include allowance for administration. BPA agrees with comments recommending an increase in the amount allowed under the program for administrative costs. BPA believes it is reasonable to increase the administrative allowance by 5 percent to allow up to 15 percent administrative costs in the rate credit and utility/federal agency bilateral contract programs. For the bilateral contracts, the 15 percent administrative allowance will be added to BPA's incentive amount that is invoiced. Small utilities will be allowed up to 30 percent for administrative costs. BPA also wants to continue to discuss with the region whether or not going forward into the next rate period with the 15 percent administrative expense is the right level or if a further adjustment is appropriate.

<u>Willingness To Pay (BPA incentives) Proposal</u>: BPA proposed a $75M/year budget to achieve 52 aMW/year. This equates to an average cost of $1.44M/aMW across the portfolio of energy efficiency programs, including the 10 percent administrative allowance and $1M/year for infrastructure support.

BPA would attempt to minimize willingness to pay adjustments. BPA may adjust payments with six months notice, if necessary, to compensate for such things as changes in codes, market prices, technology penetration or to stay on pace with targets. Adjustments would apply to measures installed after the date the adjustment notice is effective. No retroactive adjustments would be applied.

Summary of Comments Received: Some commenters suggested that BPA should allow payment up to the cost-effective level or threshold *(EPUD; Idaho Falls; Lincoln Electric; Okanogan; PPC; Richland).* Other comments recommended that BPA should not change our energy conservation measure (ECM) incentives more than once a year and only if there is a +/-10 percent change *(Hermiston; PNGC).* One comment stated that the levels BPA proposed are too low *(Pacific).* A few comments suggested that BPA should allow funding for code enforcement and count those aMW saving toward the target *(PPC; SCL; SUB)*, allowing utilities to bring in conservation at an average rate and providing an incentive to get the most savings at the least cost *(SUB).* One comment suggested that BPA pay based on value to the system (the same as C&RD does now) *(PNGC).* Another comment suggested that there was not a rationale for paying less per aMW in the bilateral contract program than in the rate credit program *(EWEB).*

Evaluation and Final Decision: As discussed earlier, BPA will increase its budget by $5M/year which results in a new weighted average cost of $1.54M/aMW across the entire program portfolio. The proposed cost was $1.44M/aMW. The increase to the new 15 percent administrative allowance and the $1M/year infrastructure support budget are covered in this revised cost target. BPA will continue to refine the details on BPA's incentives for cost-effective measures. BPA is receiving input from a Conservation Workgroup Phase 2 Committee composed of nine experienced utility representatives.

Since this is only a three-year rate period, BPA plans to make incentive payment adjustments on a six-month basis, but only if absolutely necessary. BPA is sensitive to comments that continual program changes can compromise program effectiveness. Hence, BPA will strive to implement changes as we do today on an annual basis.

Cost-Effective Measures Proposal: BPA proposed to pay only for cost-effective measures as defined by the Council in its Fifth Power Plan.

Summary of Comments Received: Many comments suggested that BPA should not use the Council's total resource cost (TRC) approach, but rather the utility-specific utility test cost (UTC) parameter and that non-energy benefits need to be included in the analysis *(Benton PUD; Benton REA; EWEB; Franklin; Grays Harbor; Lincoln Electric; Port Angeles).* Some commenters felt that the cost-effectiveness criteria BPA is relying on was arbitrary and that they did not agree with the TRC approach *(Benton REA; EWEB; Franklin; Hermiston; Umatilla).* Some comments noted that the TRC ignores values to consumers or utilities that are very real economic values *(Cowlitz; EWEB; Grays Harbor).* Several did not support limiting the list of approved ECMs to only cost-effective measures *(Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; Pacific; Richland; SnoPUD; Umatilla; Wells REC).* Other comments recommended that more residential measures be included in the approved ECM list *(Benton PUD; Port Angeles)*. Some comments suggested that BPA consider packaging like measures *(SCL; WCTED)*. One comment supported BPA's position and stated that there are other cost-effective measures not included in the Council's plan *(Council)*.

Evaluation and Final Decision: In general, conservation is considered the least-cost resource to meet increases in load demand in the Pacific Northwest. The Northwest Power Act provides that BPA support the development of cost-effective conservation. The Act includes a definition of the term "cost-effective" which applies to any conservation measure or resource BPA funds. BPA is not persuaded by comments that suggest use of an alternative standard or definition of cost-effective measures. If the region is to pursue non-cost-effective measures, then the region cannot achieve the least-cost approach mapped by the Council. BPA payment for measures that are not cost-effective has the potential to drive up BPA's overall budget and rates since non-cost-effective measures would not count against the annual 52 aMW target, since that target is for cost-effective conservation. Paying only for cost-effective conservation measure also ensures resources are being acquired at the lowest cost to the region. Both BPA's Strategic Direction (July 2004) and regional Dialogue Policy (February 2005) reinforced the achievement of "cost-effective" conservation by BPA. Thus, BPA concludes that conservation programs should follow the TRC mandate of the Council.

However, within this cost-effective constraint, BPA will make its programs as accommodating as possible toward customers' conservation strategies and priorities. For example, BPA proposed that "only cost-effective measures on the Regional Technical Forum (RTF) list would be allowed." BPA does not consider the RTF list to be exhaustive and has repeatedly said there may be cost-effective measures that can be implemented that are not on the list. For example, most industrial and almost all non-lighting commercial measures cannot be on a deemed list, yet many are cost-effective in most applications. The following provides additional clarification regarding this issue:

- Measures must be cost effective, but do not need to be on an approved measure list.
- Measures may be added through the rate period.

<u>Incremental Conservation Proposal</u>: BPA proposed that its conservation funding be used by our customers for energy efficiency savings and related activities beyond what they are required by law and/or regulatory requirements to accomplish.

Summary of Comments Received: A few comments opposed the incremental requirement stating that it was "unreasonable discrimination," that it punishes utilities that have been investing in conservation, especially in the state of Oregon, and that it sends the wrong signal *(CUB; EPUD; EWEB; OPUC; SnoPUD)*. They felt that utilities that spend 3 percent of their retail revenues on conservation should be exempt from the incremental requirement. Other commenters agreed that the IOUs should be required to provide incremental savings *(NWEC; PPC)*. Several comments suggested that NEEA contributions be allowed under the rate credit *(Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED),* although one comment agreed with BPA's proposal to not allow NEEA contributions to qualify for the rate credit *(Inland)*.

Evaluation and Final Decision: BPA agrees that customers cannot be expected to face an ill-defined threat that their conservation activities my be defined as non-incremental. For this reason, BPA will add a "state" qualifier to the statement such that it will read "required by state law or regulation." This will be used to determine incrementality. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that conservation non-incremental.

As background, incremental spending is currently required under the existing C&RD program. BPA appreciates the fact that Oregon enacted legislation that requires the state's IOUs to charge a 3 percent public purpose charge. BPA understands that this program has been successful in facilitating development of conservation and renewable resources associated with service to consumers served by the IOUs. However, BPA does not agree that it is unreasonable discrimination to require incremental spending in this case. It is not in the best interest of the region to offer a conservation credit through power rates to customers to simply subsidize programs or costs otherwise required by state law or regulation.

As explained above, BPA thus believes it is reasonable to retain the requirement that use of the CRC be incremental to spending required by state law and/or regulatory requirements.

Eligibility Proposal: With respect to eligibility to participate in the rate credit program, preference and federal agency customers are eligible to participate in the CRC and can submit proposals under the bilateral contract program, and the IOUs are eligible to participate in the CRC. BPA did not propose to make the direct service industrial customers (DSIs) eligible for the CRC or bilateral contracts programs because of the extreme financial risk associated with installing conservation measures on such unstable loads.

Summary of Comments Received: Two comments strongly suggested that DSIs should not be excluded from participation in the rate credit *(Port Townsend Paper; Alcoa).* One stated that BPA should develop non-discriminatory eligibility requirements for its programs, but if DSIs are ineligible, then they should be offered the discounted rate *(Alcoa).* On the other hand, there were some comments supporting BPA's proposal that the DSIs not be eligible for the rate credit *(SUB).* Another commenter suggested that IOUs should only be able to invest in conservation in residential and farm loads and that any IOU rate credit benefits should be carefully monitored *(Inland).* One comment stated that BPA should clarify rate credit eligibility for customers with pre-subscription contracts *(PPC).*

Evaluation and Final Decision: BPA's proposal to exclude the DSIs from participating in the CRC because as a power customer class the aluminum-related DSIs have only operated at a minimal level during the current rate period and are highly dependent on market conditions (both world alumina prices and electricity). As a result it is not clear what the measure life would be for any installed ECMs in aluminum-related facilities. The aluminum-related DSI load has been severely curtailed over recent years, particularly when power demand is reduced due to economic business conditions that are totally unrelated to energy efficiency at DSI facilities.

Therefore, BPA clarifies that only aluminum-related DSI loads will not be eligible for the CRC and bilateral contract programs.

Decrement Proposal: BPA proposed to continue its current practice of not decrementing the slice/block customers under the rate credit program, but requiring load decrements under the bilateral contracts program. The decrement would not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers would be determined on a case-by-case basis. Customers would be kept informed of any potential conservation activities in their service areas and if a decrement would be applied should they decide to participate in any proposed third-party conservation initiative.

Summary of Comments Received: Several commenters opposed any decrement and stated that the decrement is a barrier to achieving the higher conservation targets *(Benton PUD; Council; EWEB; Grays Harbor; NEEC; NWEC; PNGC; Port Angeles; SnoPUD; Umatilla)*. A couple of comments claimed the approach in BPA's proposal was inconsistent (i.e., not decrementing the rate credit, but decrementing the bilateral contracts) *(NEEC; NWEC)*. One comment suggested that decrementing the slice/block customers was appropriate *(Inland)*. Some comments suggested that BPA consider "sharing the benefits and losses" of the decrement between BPA and the decremented customers *(EWEB; NWEC;SUB)*. Another comment letter agreed with decrementing the bilateral contracts *(Lincoln Electric)*.

Evaluation and Final Decision: The issue of decrement was one of the most challenging for BPA and the Conservation Workgroup. The preponderance of views from the Workgroup were consistent with the approach proposed by BPA, which is basically to continue the decrementing policy being used in the 2002-06 rate period. Based upon input BPA received, BPA believes that the "no decrement" decision is warranted under the rate credit program and under the NEEA contract. In these instances BPA is providing funding through the CRC or via a funding mechanism to a regionally supported conservation organization. BPA is not directly expending dollars to acquire conservation savings from these parties to meet and serve BPA's firm power load obligations. Thus, while BPA will take into account any actual conservation savings achieved through these programs, BPA will not correspondingly reduce or decrement the amount of federal power customers are eligible to buy from BPA. On the other hand, customer participation in bilateral conservation acquisition contracts with BPA could result in reduction in the amount of federal power being purchased to the extent such contracts obligate the customer to deliver actual energy savings. BPA believes, as stated in the original proposal, that decrementing is important to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving conservation at the lowest possible cost.

<u>Donations Proposal</u>: Third-party subcontracts with energy organizations would be allowed provided cost-effective aMW savings result. Utilities could not take administrative payments on pass-through contracts. Administrative costs must be tied to actual program delivery. Because BPA contracts directly with NEEA to conduct market transformation activities on behalf of all the loads paying into the conservation budget, utilities would not be allowed rate credit reimbursement for contributions to NEEA.

Summary of Comments Received: Many commenters suggested that BPA allow rate credit reimbursement for NEEA donations and BPA should count the associated aMW savings toward the target *(Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED)*. One comment expressed support for not allowing NEEA donations under the rate credit *(Inland)*. Several commenters indicated that we should not limit donations to low income weatherization since BPA is requiring the funds only be spent on cost-effective measures *(EPUD; EWEB; PSE; SUB)*.

Evaluation and Final Decision: In part because of the almost unanimous support for a change to BPA's proposal, BPA has decided to allow the rate credit to be used for contributions to NEEA. BPA will include these funds in determining its share of the NEEA aMW achieved and will count those aMW toward its new target. Third-party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. For example, if a utility chooses to subcontract with a local low-income (CAP) agency, the utility might specify that its funds go towards CFL installations in low income homes. There will be no cap on these types of activities since they will produce cost-effective conservation savings.

Small Utility Option Proposal: BPA proposed that small utilities (defined under the C&RD as those with a total load of 7.5 aMW or less) would be required to pursue cost-effective conservation measures that are achievable in their service area if they chose to participate in BPA's conservation programs. A variety of options and tools will be available for small utilities. These options and tools would provide several avenues to make it practical for even very small utilities to participate without incurring overly burdensome overhead (e.g., standard offers, off-the-shelf programs and templates, pooling, third-party options, etc.). A small utility could choose to use anywhere between 0 percent to 20 percent of its rate credit for administrative costs. Some small utilities could choose to simplify their spending of their rate credit by purchasing renewables. Small utilities would report savings through the RTF database in the same manner that all other utilities report.

Summary of Comments Received: Some commenters recommended that BPA retain the existing C&RD small utility policy *(Columbia Power; NRU; PPC)*, with one commenter recommending that the threshold should be increased from the current 7.5 aMW to 15 aMW *(Irecoop)*. One commenter requested further clarification of what small utilities could do to qualify for their rate credit *(NRU)*. Some commenters did not want the *pro rata* approach for renewables to apply to small customers *(Fairchild AFB; USDOE-Richland)*.

Evaluation and Final Decision: BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. BPA will make several changes in response to comments to help make small utility participation feasible. BPA will include up to 30 percent for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the $6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 1. These changes, and others BPA will seek through ongoing work with these utilities, should facilitate small utilities' achievement of conservation and renewables with rate credit dollars within their limited staff resources. BPA will keep the 7.5 aMW size limit definition and maintain the proposed requirement that small utilities acquire cost-effective conservation (or renewables) in order to participate in the rate credit program.

Third-Party Involvement Proposal: BPA proposed that this third-party contract component of the program portfolio would allow BPA to contract to third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. In general, regional programs would be designed to operate in coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. These third-party contracts may include activities such as the market transformation efforts of NEEA, bulk purchases and vendor programs.

Pre-committed funding for NEEA ($10 million per year for the next three years) is included in this mechanism, and no decrement is proposed for the NEEA bilateral contract.

Key Features

- Reasonable administration costs for third-party contracts would be negotiated.
- Region-wide programs and efforts would be coordinated with local utilities.
- A determination of whether or not a decrement applies for other third-party programs would be determined on a case-by-case basis.
- Customers would be kept informed of conservation activities in their service territories and whether or not a decrement would be applied.

Summary of Comments Received: Many comments indicated that third-party bilateral contracts were OK, but only with local utility approval for the vendors to work in their service areas *(Benton PUD; Franklin; Hermiston; Lincoln Electric; Okanogan; PPC; PNGC; Richland; Umatilla)*. One commenter endorsed the approach if cost-effective savings result *(Inland)*.

Evaluation and Final Decision: BPA will contract with third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy and is consistent with the recommendations of the majority of the comments BPA received on this issue. The use of the phrase "customers would be kept informed" in the proposal about third-party contractors was not intended to imply any change from the current policy of getting utility agreement for third-party activity before sending any third parties to do BPA funded conservation in the service territories of our customers. BPA believes having access to third-party vendors as part of it overall conservation portfolio would help lower the cost of acquiring conservation, especially when it needs to affect markets that cannot be changed at a local level. Utilities will not face a decrement for conservation done by third parties without their prior agreement to that result.

<u>Rate Credit Performance Requirements Proposal</u>: BPA proposed that utilities would report at least semi-annually to BPA. Use of the RTF reporting software would be required. If, at the first semi-annual report, the utility was not meeting its targets (50 percent or less of its expected rate credit spending), the utility would have to prepare and have BPA approve an action plan that provides sufficient proof of achievable intent by the end of the first year after the program starts. If by the third semi-annual report the utility was not performing (i.e., is 75 percent or less than its expected rate credit spending progress), BPA would have the option of cutting off the rate credit at the beginning of the third year. At the end of the third year of the rate credit program, there would be a true-up required for all participating utilities.

Summary of Comments Received: Several commenters supported the six-month reporting requirement *(Cowlitz; Pacific; PNGC)*. One commenter recommended that the initial check-in occur after one year rather than at six months *(Canby)*. Another commenter recommended reporting on a quarterly basis *(Council)*. A few commenters recommended that BPA re-evaluate the rate credit program if the goals are not being met *(Lincoln Electric; Okanogan; PPC)*. Another commenter suggested that peers rather than BPA should judge performance and be able to suggest remedies for the BPA program design *(SUB)*.

Evaluation and Final Decision: BPA's goal is to achieve the targeted rate credit aMW by the end of the rate period. A shorter rate period (three years instead of five) coupled with the need for utilities to develop and field programs to target cost-effective technologies that many utilities are not currently targeting, means utilities will need to develop and implement a plan early in the new rate period for achieving the conservation. BPA realizes it may need to provide tools and resources to assist utilities in this effort. The semi-annual reporting will enable BPA to identify and provide assistance to those utilities who need additional help soon enough that the targets for the rate period can be met.

BPA's intent is to provide assistance to utilities as needed to ensure the rate credit aMW is achieved. The reporting requirement provides the "flag" that allows BPA to identify and assist those utilities that need help. BPA will retain the requirement for semi-annual progress reports via the RTF reporting system. To address commenters' concerns, utilities will need to submit an Action Plan only if sufficient progress has not been made (i.e., 50 percent or less of its expected rate credit has been spent) at the end of the first full program year. BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. At the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities to make sure BPA's rate credit funds were spend on qualified measures. BPA is making these changes because it understands the concern about having a hard spending requirement too early in the new program's start-up period.

With regard to the bilateral contracts, since these are pay-for-performance type contracts, BPA will have a pretty good idea of how the delivered savings are proceeding. However, BPA will retain the right to withdraw budget commitments if participants are not making sufficient progress on delivering the agreed upon savings. This will be done on a case-by-case basis and in conjunction with the affected customer.

Oversight Proposal: Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting.

(a) BPA proposed that BPA or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.

(b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit would include (but is not limited to): a review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

Summary of Comments Received: Regarding the rate credit, several commenters were concerned about the oversight being overly burdensome (i.e., don't use the past receipt and acceptance approach) *(Benton REA; Cowlitz; Lincoln Electric; Okanogan; PPC; Umatilla)*. Some of the commenters suggested that only one audit should be necessary over the third-year rate period if participants are in substantial compliance *(EPUD; Hermiston; PPC; PNGC; Umatilla)*. A few commenters indicated that our current ConAug oversight approach should be used for the rate credit *(Hermiston; Port Angeles; SCL)*. One commenter recommended that BPA consider relying on participants' CPA or state auditors to meet BPA financial audit requirements *(Umatilla)*. Another commenter objected to creating third-party transactions whereby BPA interfaces with end-users *(SUB)*. One commenter recommended that reporting not be broken down to member level of pooling customers *(PNGC)*.

Evaluation and Final Decision: To carry out its fiduciary responsibility, BPA believes that it must preserve the oversight rights described in its proposal. Although the detailed contract language on "oversight" has extensive language about the rights BPA has, the actual implementation of the oversight has not been onerous. Utilities experienced with ConAug oversight reiterated that it has not been a burden in reality. The Conservation Workgroup recommendations endorsed this approach to oversight for the new rate credit program. BPA does want to clarify that it will require only one oversight visit per year under the rate credit program and that it will try to coordinate that visit with any bilateral contract oversight requirements, if reasonable. Accordingly, BPA will aim to have one oversight visit for all of its conservation programs for each participating utility, unless major issues surface.

Another clarification relates to confusion about another utility performing oversight on a customer's contracts. This was never intended. Third-party evaluation contractors could be used for evaluations, but they will perform confidential work for research purposes not contract oversight. No utilities will be tasked with looking at the books of other utilities.

Renewables Proposal: BPA proposed a renewables option under the rate credit program that requires customers to commit up-front as to the portion of their rate credit they will apply to renewables for the full three years of the rate period and to do so by 7/1/06. This up front commitment would provide certainty of the amount of rate credit money that was available for conservation. Further, BPA proposed capping the level of renewables funding under the rate credit to $6 M/year. If customers subscribe for more than $6M/year, then BPA proposes to pro rate their shares down to the $6M/year cap.

Summary of Comments Received: Some commenters recommended that BPA allow annual sign-ups for renewables, rather than a three-year commitment up-front as proposed *(Benton*

REA; PPC). A few commenters indicated that they would like to continue to have an option of purchasing green power under the new rate credit *(Benton PUD; PPC; USDOE-Richland)*. In addition, some commenters recommended that the federal customers should not be subject to pro-rating *(Fairchild AFB; USDOE-Richland)*. Another commenter wanted BPA to reconsider the pro-rating approach for over subscription on renewables *(SnoPUD)*. One commenter was opposed to the $6M/year renewables cap *(Interfaith GWC; Whatcom)*. Some commenters wanted customer-side renewables and related R&D funded under the rate credit *(EPUD; EWEB; Ferry County; SCL)*.

Evaluation and Final Decision: Consistent with commenters' recommendations, BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a $6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This will provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds but provides additional flexibility for customers that manage their rate credit on an annual basis. Exempting small utilities and federal agency customers from the *pro rata* requirement will not compromise the plans these customers may put in place satisfy their rate credit obligations. BPA will issue for public review and comment a menu of renewable resource-related activities that will qualify for the rate credit prior to the program start date.

Starting Programs Early Proposal: BPA proposed to begin the CRC program when the new rate period started (i.e., October 1, 2006). Also, BPA planned to have the new bilateral contracts ready for signature in the fall of 2005, but not provide any funding until the new rate period started (i.e., again, October 1, 2006).

Summary of Comments Received: A few commenters recommended that BPA allow customers that have met their C&RD spending requirements to start funding projects/programs for the new rate credit early (e.g., similar to what BPA did with the C&RD during the 2001-02 energy crisis) *(Benton PUD; Idaho Falls; Wells REC;)*. One commenter recommended that BPA allow for a smooth transition to future programs and that BPA should provide an option for customers to discontinue their participation in the rate credit *(Idaho Falls)*.

Evaluation and Final Decision: BPA has worked hard over the last several years to provide stable level funding for its conservation programs. Allowing customers to implement the new programs early will provide continuity in the delivery of cost-effective conservation and helps avoid a potential "slow-down" in the achievement of aMW savings as customers transition from the old programs to the new ones. Accordingly, BPA, in response to the comments received on this issue, will allow customers that have used all their C&RD credits and have filed a final close-out report to spend their funds under the new rate credit starting in CY 2006 (targeted for January 1, 2006) and claim spending on approved, cost-effective ECMs when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. *(Note: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the current rate period.)*

In response to a commenter's request, BPA will include a mechanism or procedure for customers to discontinue participation in the rate credit should they choose to do so. However, the customer has to continue to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

Also, in response to commenters' recommendations and because BPA recognizes some customers may slow down their bilateral program efforts until the new bilateral contracts are available for execution, BPA will offer new bilateral contracts for execution this fall (targeting October 1, 2005). This will allow customers to begin implementing projects under the new contracts (with the new rules and incentive levels) during the current rate period. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

<u>Attachment 1</u>

Post-2006 Conservation Program:
Small Utility Option under the Conservation Rate Credit

Keep the 7.5 aMW size limit and maintain the requirement that small utilities must acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements would be available to small utilities with an annual CRC that is less than $32,851:

- Allow up to 30 percent of their CRC amount to be used for administrative costs, to include any information, education and outreach (marketing) efforts regarding energy efficiency.

- Require only one BPA oversight visit during the three-year CRC rate period (unless the utility requests a more frequent review).

- Allow use of a third party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third party).

- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
  - CFL programs
  - Appliance Rebate programs
  - SGC Manufactured Homes program
  - Energy Star New Construction program
  - Other qualifying cost-effective measures and standard offers

However, if small utility customers don't have sufficient opportunities to implement cost-effective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Allow donations for cost-effective measures to low-income weatherization organizations with no cap (e.g., CFLs).

- Allow purchase of the renewables (with no *pro rata* adjustment if renewables are over subscribed ((i.e., exceed $6M/year cap)) by CRC participants).

- Allow donations to NEEA (or other organizations that will use BPA's funds to install cost-effective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.

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APPENDIX D
Post-2006 Program Structure

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Energy Efficiency
Bonneville Power Administration

Final Post-2006 Conservation Program Structure

This document describes BPA's final Post-2006 Conservation Program structure. A companion document, "Response to Key Issues Raised in Public Comment Process," summarizes the key issues raised in the 56 public comment letters and e-mails BPA received regarding BPA's Post-2006 Conservation Program Proposal. The companion document also summarizes BPA's final decisions on these key issues that are incorporated into this final program structure. This document is organized as follows.

Section I: Introduction. The program purpose and BPA's strategic direction are described in this section. The five-year (FYs 05 – 09) aMW targets are identified. The five program principles that were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy are described along with seven key policy directives that help frame the post-2006 conservation programs. Finally, the timeframe anticipated for implementation of these final programs is explained.

Section II: Program Portfolio and Structure. This section includes a description of the portfolio of programs followed by a more detailed description of program design features for each of the four portfolio components: a rate credit; utility and federal agency customer bilateral contracts; third-party contracts; and regional infrastructure support. Features that are consistent across all programs are identified up front. Oversight requirements and tracking and reporting activities are described in Appendix 1 and the small utility option for the rate credit program is described in Appendix 2.

Appendices:
1. Sample of BPA Reporting, Oversight, and Evaluation Requirements.
2. Small Utility Option under the Conservation Rate Credit

I. Introduction

Purpose

The purpose of this document is to describe the portfolio of programs that BPA will offer during the 2007 through 2009 timeframe and through 2011 (pending the outcome of post-2009 rate case decisions and/or future long-term power sales contract requirements). BPA anticipates that this portfolio will: (1) facilitate BPA's ability to achieve its share of the regional conservation targets as defined by the Northwest Power and Conservation Council's (Council) Fifth Power Plan; (2) enable BPA to achieve its strategic objective described below; and (3) provide consistency with BPA's Regional Dialogue policy decisions. In addition, the seven BPA policy directives described below provided supplemental guidance to the portfolio design.

Strategic Direction
Strategic Objective 3: BPA ensures development of all cost-effective energy efficiency in the loads BPA serves, facilitates development of regional renewable resources, and adopts cost-effective non-construction alternatives to transmission expansion.

Explanation of S3: BPA will continue to treat energy efficiency as a resource and define our goals in terms of megawatts of energy efficiency acquired. Even if we adopt tiered rates, we are very likely to continue to need limited amounts of new resources. We expect conservation to continue to be a cost-effective resource to meet this limited need, with first priority by law. Accordingly, our goal is to continue to ensure that the cost-effective conservation in the load we serve gets developed, since this amount is very unlikely to exceed our total need. We will ensure this amount is developed with the smallest possible BPA outlay. We will do this through a combination of acquisition of conservation, adoption of policies and rates that support others' development or acquisition of cost-effective conservation, and support of market transformation that results in more efficient electric energy use.

Program Principles
The following five conservation principles were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy (dated February 2005). They provide the framework for future conservation program design purposes.

- **Conservation Targets from Council's Plan:** BPA will use the Council's plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent[1]) of cost-effective conservation is based.

- **Conservation Achieved at the Local Level:** The bulk of the conservation to be achieved is best pursued and achieved at the local level. There are some initiatives that are best served by regional approaches (for example, market transformation through the Northwest Energy Efficiency Alliance). However, the knowledge local utilities have of their consumers and their needs reinforces many of the successful energy efficiency programs being delivered today.

- **Achieve Conservation at Lowest Cost Possible to BPA:** BPA will seek to meet its conservation goals at the lowest possible cost to BPA. While only cost-effective measures and programs are a given, the region can benefit by working together to jointly drive down the cost of acquiring those resources.

- **Administrative Support:** BPA will continue to provide an appropriate level of funding for local administrative support to plan and implement conservation programs.

- **Funding for Education, Outreach and Low-Income Weatherization:** BPA will continue to provide an appropriate level of funding for education, outreach, and low-income weatherization such that these important initiatives complement a complete and effective conservation portfolio.

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[1] Based on the FY03 White Book information.

In addition to the five approved principles listed above, BPA's Post-2006 Conservation Program Structure is guided by the following key policy directives:

- **Benefits Must Flow to BPA:** BPA must realize directly the benefit of the savings achieved from the conservation acquisition programs it funds. (Note: the decrement will only be required in conjunction with slice/block customers' bilateral acquisition agreements and in some third-party contractor programs, as appropriate and with utility agreement.)

- **Cost-Effective Measures:** BPA will only pay for cost-effective measures as defined in the Council's Power Plan.

- **Accountability:** BPA needs to be sure it is getting what it pays for -- incremental, reliable and verifiable conservation savings. Measurement and verification will be included in all program mechanisms. This will include managing performance risks upfront such that BPA will avoid any need to "backstop" underachievement.

- **Tracking Progress:** BPA will monitor and report, on a regular basis, how our utilities and other parties are spending the conservation funds it provides across all components of the conservation portfolio.

- **Flexibility:** BPA will retain flexibility to shift budgets and targets across all program elements of the conservation portfolio and across program years to ensure the Council's target is met at the lowest cost possible.

- **Leveraging and Coordination:** BPA will coordinate and synchronize its efforts with those of others as part of an effective and efficient regional effort to achieve cost-effective conservation.

- **Local Control:** BPA will foster local utility initiative and control of conservation efforts to the maximum extent it can, consistent with meeting cost and verification goals.

Timeframe
It is anticipated that this program structure will be implemented for BPA's FYs 2007 to 2011 period. However, new power sales contracts and/or post-2009 rate case decisions may require that elements of this program structure be adjusted. This program approach will be ready for implementation on or before October 1, 2006. BPA will allow customers that have used all their C&RD credits and have filed a final closeout report to spend their funds under the new rate credit starting in calendar year 2006 (targeted for January 1, 2006) and to claim spending on approved, cost-effective measures when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. Only qualified ECMs implemented after the customers have satisfied their C&RD obligations and indicated to BPA that they want to begin the new program will be allowed. *(Note: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the start of the current rate period.)* BPA will include a

mechanism or procedure for customers to discontinue participation in the rate credit. However, should they choose to discontinue participation, they will have to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

BPA will offer new bilateral contracts for execution by customers in the fall of 2005 (targeting October 1, 2005). Customers may choose to close out current ConAug contracts and transition to new bilateral conservation acquisition agreements. Customers can begin implementing projects and receiving reimbursement from BPA under the new contracts (with modified terms and incentive levels) once the new contracts have been executed. However, commercial and industrial projects already purchased or approved under ConAug will be subject to the current ConAug incentive levels and contract terms. Payment for projects under the new bilateral contracts can only occur after the execution date for the new agreement. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

Commitment to Achieving the Target: BPA believes it is important to maintain a steady level of support for conservation over time and will continue to provide a strong energy efficiency program with a firm commitment to achieving its share of the Council's conservation target. This commitment has been demonstrated in the current rate period. BPA more than quadrupled its budget for installing energy conservation measures and capturing conservation savings from about $15M in 2001 to over $70M in 2002. Since that substantial increase in funding for conservation, BPA has maintained a high level of support for delivering conservation savings each year. In the 2007-09 rate period, BPA proposes to continue this support and increase the funding level from about $70M/year, on average, to $80M/year, on average.

II. Program Portfolio and Structure

Program Design Features

BPA's Post-2006 Conservation Program is a portfolio of programs and supporting activities designed to achieve BPA's share of the regional cost-effective conservation target (as identified by the Council's Fifth Power Plan). The portfolio includes: (1) a rate credit program; (2) utility and federal agency customer acquisition program; (3) third-party acquisition initiatives; and (4) support for regional infrastructure necessary to effectively carry out the other portfolio elements. Options are provided under the rate credit program for small utilities. In addition, under the rate credit program, a renewables alternative is provided.

The program portfolio is shown in the following chart and explained in further detail in the remainder of this document.

Post 2006 Conservation Program aMW Targets

Based upon the Council's Fifth Power Plan, there is a regional conservation target over the 2005-2009 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA will adjust the amount of its target to take

BPA's Final Post-2006 Conservation Program Structure

- **Rate Credit Program** (no decrement)
  - Standard offers, deemed, protocol & custom measures
  - Reporting through enhanced RTF database system
  - Administrative costs included
  - Financing/revolving loan option
  - Continue pooling option
  - Optional contracting w/ service providers
  - Measurement & Verification
  - Proposal reviews, optional pre-approval, BPA technical assistance
  - Monitoring, reporting & tracking
  - Cost-effective LIWx & direct application renewables
  - Renewables alternative
- **Utility & Federal Agency Customers Bilateral Contracts** (decrement applies)
  - Standard offers, deemed, protocol & custom measures
  - Reporting through enhanced RTF database system
  - Administrative costs included
  - Proposal reviews, optional pre-approval, BPA technical assistance
  - Measurement & verification
  - Option for pooling & contracting with third-party service providers
  - Monitoring, reporting & tracking
- **Third-Party Contracts** (decrement TBD)
  - Market transformation incl. codes & standards (no decrement)
  - Bulk purchases
  - Vendor programs
  - Monitoring, reporting & tracking
  - Measurement & verification
- **Regional Infrastructure Support**
  - BPA & collaborative region-wide RD&D
  - BPA & collaborative evaluation
  - Peer sharing & training
  - BPA's share of support for RTF
  - Coordinated regional marketing education & outreach

into account the estimated amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). This results in an average annual conservation target of 52 aMW/year for a total of 260 aMW over the 2005-2009 period. BPA will increase its near-term conservation targets for the 2005-09 period, rather than the originally proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY 2006. To meet the 52 aMW/year target in 2005 and 2006 (i.e., an additional 8 aMW/year from the Council's new target), BPA will seek to acquire an additional 16 aMW in 2006.

BPA will conduct an evaluation to estimate the accuracy of this assumption about naturally occurring conservation and whether the assumption should be modified going forward. BPA's commitment is to ensure development of the five-year target, recognizing that there will be variations in the pace of the delivered savings on an annual basis.

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target. For example, BPA will count 50 percent of NEEA's conservation acquisition towards BPA's targets since BPA provides 50 percent of NEEA's funding. BPA will also count the conservation savings that result from IOU rate credit expenditures.

Eligibility
All BPA customers (including the IOUs), with the exception of the aluminum-related DSIs, will be eligible to participate in the rate credit program. All BPA preference and federal agency customers will be eligible to participate under the bilateral contract program.

Incremental Requirements
BPA's conservation funding must be used by our customers for energy efficiency savings and related activities beyond what they are required by state law and/or regulatory requirements to accomplish. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that funding non-incremental.

Decrement
BPA believes, as stated in the original proposal, that decrementing is necessary to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA will continue its current practice of not decrementing the slice/block or participating IOU customers under the rate credit program, but will continue requiring a load decrement for these customer groups in conjunction with the bilateral contracts program. The decrement will not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers will be determined on a case-by-case basis. Customers will be asked if they want to participate in any third-party program in their service area. Customers will be informed if a decrement applies to the program at the time they are asked.

This approach continues the policy we currently apply and ensures that BPA realizes a load reduction from the conservation BPA pays for and that BPA and its customers see the full benefit from the conservation acquisitions. For the rate credit program, this approach, while not resulting in a BPA load reduction, reduces a barrier to utility participation in BPA's conservation programs and is consistent with the Conservation Workgroup's recommendations. However, BPA does not believe this approach is consistent with how conservation should be acquired, so the decision to not decrement the rate credit program for the 2007-09 rate period is not meant to set any precedent for future conservation program activities post 2009.

BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving cost-effective conservation at the lowest possible cost.

Renewables Alternative
Under the rate credit program, eligible customers can choose to use their credits for qualified renewable resource related activities. BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a $6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This is intended to provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds, and provides additional flexibility for customers that manage their rate credit on an annual basis. A list of eligible renewable measures will be distributed for public review and comment prior to the start of the new rate credit program.

Budget
BPA's annual budget (capital and expense) for acquiring the target of 52 aMW/year is $80 million (see Table 1). BPA has an additional $6 million per year from BPA's Generating Renewable Program Fund for renewables. For the 2007 – 2009 rate period, the rate credit will be $0.0005/kWh (1/2 mill) on utility-purchased power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly $42 million (including

Table 1: Program Annual aMW Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year with IOUs and Pre-Subers included)**	20	$36M	$1.8M
Utility & Fed. Agency Bilateral Contracts**	17	$26M	$1.5M
Third- Party Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$ 1M	---
Total	52	$80M	$1.5M

* Assumes $6M/year of the $42 M/year from a separate renewable budget will be spent on renewables.

** Includes a 15 percent administration allowance.

participation by pre-subscription contract holders and IOUs). BPA anticipates that $6 million per year will be spent on renewable resource related initiatives. As shown in Table1, BPA will pay a weighted average of $1.5 M/aMW (which includes a 15 percent administration allowance for the rate credit and bilateral contracts programs) across the entire portfolio of programs.

Features Consistent For All Programs

There are several features that will be consistent across all of the conservation programs:

- BPA will pay only for qualified cost-effective measures from the RTF list as defined by the Council's Fifth Power Plan, as well as for approved calculated and custom program designs, and for additional deemed measures that are approved throughout the rate period.
- The list of qualified, cost-effective measures, deemed kWh savings and payment rate per measure will generally be consistent across programs. However, BPA retains the flexibility to negotiate custom agreements.
- BPA's willingness to pay may vary by sector and measure, and will reflect the actual cost to acquire resources in each sector. It may also reflect program implementation realities.
- BPA's will consider measure life in our determination of willingness to pay levels for specific measures.
- BPA will strive to simplify implementation by using averages that take advantage of measure similarity.
- Packaging of measures will be allowed, but BPA will only pay an amount equivalent to payment for the cost-effective measures in the package.
- BPA will attempt to minimize the frequency of adjustments to willingness to pay adjustments. For example, BPA may adjust payments with six months notice, if necessary, to compensate, for changes in codes, market prices, technology penetration or, if needed, to stay on pace with targets. Adjustments will apply to measures installed after the date the adjustment notice is effective. No retroactive adjustments will be applied.
- Utilities may request the RTF review the eligibility of new measures or measures previously deemed to not be regionally cost effective. If the RTF recommends the requested measures as cost-effective, BPA will review the RTF's recommendations to determine whether or not BPA will pay an incentive for the measure.
- Semi-annual reporting will be required.
- BPA retains the flexibility to shift funds between programs and program elements, and across fiscal years as needed to ensure the conservation targets are achieved at the lowest cost possible.
- Oversight and verification will be similar to the current requirements under the ConAug program. Participating utilities will be required to support evaluations (see Appendix 1).
- Information on individual utility expenditures and achievements resulting from BPA funding will be made available to the public, as appropriate.

Rate Credit Program

Overview

A rate credit will be established to facilitate local development of conservation. The aMW purchased with rate credit money will be counted towards BPA's aMW target. Load forecasts will not be reduced and no decrement off block or slice will be required. If IOU's participate, they will participate under the same rules and conditions that apply to all utilities. Utilities will make a commitment to BPA if they plan to participate in the rate credit program no later than three months prior to the start of the rate period (program start October 1, 2006; notification to participate required by July 1, 2006). The utility will make the commitment by submitting a letter to BPA that states that the utility will participate and that the utility agrees to abide by the program rules as documented in the appropriate GRSPs and the Implementation Manual. If a utility chooses to discontinue participation, the utility must provide BPA notice no later than July 1 for the following October 1 to September 30 fiscal year period. A Rate Credit Implementation Manual, similar to the existing C&RD Implementation Manual, will be prepared and distributed approximately six months prior to program implementation and three months before utility commitments to the rate credit are required. An overview of this program is shown on the chart. Key features of this proposed program include:

Key Features

- Customers may choose to be reimbursed from the rate credit for administration costs at a rate of up to 15 percent of the customer's eligible annual rate credit.
- Monthly credit amount is equal to the forecasted eligible annual credit/12.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- Rate credits will be provided for qualified deemed, deemed calculated, custom/protocol projects and standard offers.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available
- Utilities will report at least semi-annually to BPA via the RTF reporting system. If, at the second semi-annual report (end of the first full year of the program), the utility is not meeting its targets (50 percent or less of its expected rate credit spending), the utility will have to prepare and have BPA approve an Action Plan that provides sufficient proof of achievable intent by the end of the first year after the program starts (10/1/07). BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report – 4/1/08) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. After the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities.
- The existing RTF web-based information and reporting system will be used. The RTF database will include all measures in the current C&RD database and the cost-effective measures for which BPA is willing to pay an incentive during the new rate period (FYs 2007-09). The reporting system will be enhanced to include means for utilities (at their option) to enter savings acquired from non-cost-effective measures, measures the utility pays for with its own money, and for identifying savings from lost opportunity measures.
- Measurement and verification for non-deemed measures at a level similar to that done under the current ConAug program will be required (see Appendix 1).

- Utility records related to spending of BPA funds will be subject to federal financial review.
- BPA will conduct an annual oversight visit (see Appendix 1 for further detail).
- Pooling of utility funding is allowed (optional), but there will be a 15 percent cap on total administration costs for the pool.
- Utilities may contract independently with third-party service providers to operate their programs (optional).
- An annual commitment to renewables will be allowed (see earlier Renewables Alternative section).

Rate Credit Eligibility

- Only qualified, cost-effective conservation and direct application (customer side) renewable measures will be eligible for a rate credit and renewables option.
- There will be a no cap on the total dollars in the rate credit program that a utility may either contract to low income weatherization organizations or spend on utility low income programs. No double counting of savings will be allowed, and utilities may not claim administration costs on the amount of money contracted or passed through.
- Third party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. Utilities may not take administration payments on pass-through contracts. BPA will include these funds in determining its share of the NEEA aMW achieved and will count these aMWs toward BPA's target.

Small Utility Option

Overview

Small utilities are defined as those with a 7.5 aMW or smaller total load. BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. Small utilities will be required to acquire cost-effective measures (or renewables) in order to participate in the rate credit program. BPA will allow up to 30 percent of their rate credit for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the $6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 2.

Utility and Federal Agency Bilateral Contracts Program

Overview

BPA anticipates this bilateral program component of the program portfolio to be a five-year program and is committing funding for a three-year period (2007 though 2009). This program is needed because the conservation resources are not evenly distributed across the region. BPA may shift money between the bilateral contract and other programs in the portfolio, as appropriate.

Streamlined, standardized umbrella agreements will be written with interested utilities (participation is optional). Similar to the current ConAug program, each agreement will have exhibits that provide specific program details. Utilities can select from available program exhibits to customize the selection of programs best suited to their service territory. BPA will fund both standard offer and custom designed programs. BPA (or its designated contractor) will conduct oversight. BPA will make a budget commitment to the utility for the duration of the contract subject to utility performance. Similar to the current ConAug program, BPA (or its designated contractor) will provide limited engineering assistance for project scoping and, if requested, pre-approval of projects. The proposed Utility and Federal Agency Bilateral Program is an acquisition program and, as such, the decrement will apply to all slice/block customers. Key features of this proposed program include:

Key Features
- Reimbursement of administration costs at a rate up to 15 percent of the allowable costs may be included with the project budget and reimbursed by BPA.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available.
- Measurement, verification and oversight will be similar to that done under the current ConAug program.
- Incentives will be provided for qualified deemed, standard offers and custom/protocol projects.
- BPA will explore augmenting the existing RTF database to allow bilateral contract reporting -- so that tracking for both programs will be through the same database. Invoicing for BPA payment will be separate.
- Stranded cost repayment provisions will be put in place between each participating utility and BPA.
- BPA will strive to provide simplified contracts.
- BPA will strive to provide a streamlined approval process

Measure Eligibility
Only qualified cost-effective conservation and direct application (customer-side) renewable measures will be eligible.

Third-Party Contracts

Overview
This third-party contract component of the program portfolio will allow BPA to contract to third parties when these contracts will lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy. In general, regional programs will be designed to operate in coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. BPA anticipates transferring funds between third-party contracts and utility and federal agency bilateral contracts,

as needed, to balance the level of effort needed at both the regional and local levels and to achieve the targets at the lowest possible cost.

Pre-committed funding for NEEA ($10 million per year for the 2007-09 period) is included in this mechanism and no decrement will be applied for the NEEA contract.

Key Features

- BPA will negotiate reasonable administration costs for third-party contracts.
- Region-wide programs and efforts will be coordinated with local utilities.
- The decrement will not apply to NEEA.
- A determination of whether or not a decrement applies for other third-party programs will be determined on a case-by-case basis.
- Customers will be notified as to whether or not a decrement will apply to any third-party program of interest to the utility before the utility agrees to participate.

Infrastructure Support

Overview

A number of proposed support activities will be undertaken to optimize expenditures through BPA's energy efficiency programs, to leverage other available resources and to reduce the overall cost of accomplishing the conservation. These activities may include:

- Setting up a mechanism for peer sharing (e.g., so utilities can share successful program ideas and marketing materials).
- Conducting limited BPA and collaboratively funded RD&D to ensure we are developing the next wave of energy efficiency technologies.
- Performing evaluations (process and impact) and market assessments to ensure BPA's programs are achieving the intended result and to gather the information necessary to make mid-stream program adjustments. Co-funding from other affected organizations may be solicited for these evaluations/assessments. BPA may also contribute to a regional evaluation designed to assess how much naturally occurring conservation has been achieved.
- Enhancing and supporting the RTF database to include expanding the reporting elements and website to allow bilateral contract acquisition reporting and tracking and to track lost opportunity acquisition.
- Developing, with utility guidance, tool kit components such as utility program marketing and implementation materials that utilities need and may choose to use to launch new programs.
- Developing templates and other program design "off the shelf" materials that small utilities can easily use.

Tracking and Reporting

BPA is upgrading the RTF/C&RD database to allow utilities to report both bilateral and rate credit program accomplishments in an on-line database. BPA will continue to rely on invoicing for reimbursement under bilateral agreements. BPA is also expanding the database to allow utilities to report conservation savings from other funding sources as well.

Appendix 1
Sample of Reporting, Oversight, and Evaluation Requirements

Reporting:

Purpose: Tracking progress to meeting the regional goals in real time will be important if the region is going to be able to respond and adapt to shortfalls. In addition, the use of public funds requires a minimum level of accounting.

All utilities will report at least semi-annually, using the RTF database, on their accomplishments and expenditures of funds, whether from the rate credit or bilateral contracts. BPA will strive to have this single source of reporting meet as many needs as possible to avoid duplicative or inconsistent reporting needs. All data received will be in the public domain except where consumer business confidentiality is needed.

Oversight and Verification:

Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting. BPA will aim to have one oversight visit per year for all of its conservation programs for each participating utility, unless major issues surface.

(a) Bonneville Power Administration (BPA) or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review a utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.

(b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit will include: review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

Evaluations:

Purpose: Evaluations are needed to determine barriers to program success, identify ways to improve programs, help track program accomplishments, and to assess the market conditions, the accuracy of the savings estimates, and to answer the ultimate question of whether programs are meeting their expected goals.

(a) BPA may conduct, and the utility shall cooperate with, evaluations of conservation impacts and project implementation processes to assess the amount, cost effectiveness, and reliability of conservation in the utilities' service areas or region. After consultation with the participating utilities, BPA shall determine the timing, frequency, and type of such evaluations.

(b) BPA anticipates that many of the evaluations will be done collaboratively with other organizations to share costs and improve the usefulness of the evaluations. In some cases, this will result in the evaluation being managed by another party on behalf of BPA and others. Such evaluation contract management responsibilities might be shared with other parties, including among others, the NEEA, the RTF, the Power Council, the Energy Trust of Oregon, or another utility.

(c) BPA will determine the specific requirements for evaluations with consideration for the schedules and reasonable needs of the utility and the utility's customers.

(d) Unless requested by the program managers to improve program operation, any evaluation of the project initiated by BPA shall be conducted at BPA's expense or shared regional expense and such costs shall be excluded from the implementation budget. Utility or other entities who cooperate with the evaluation are implicitly recognized as providing some resource/cost, but will not be considered for direct reimbursement by BPA, except under unusual circumstances. Cooperation with the evaluation is a cost of the partnership in delivering the programs.

Appendix 2
Post-2006 Conservation Program:
Small Utility Option under the Conservation Rate Credit

BPA will continue to define small utility as those utilities with loads of 7.5 aMW or under. BPA intention is that small utilities acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements will be available to small utilities:

- Up to 30 percent of a small utility's CRC amount may be used for administrative costs, (which include information, education and outreach (marketing) efforts regarding energy efficiency).

- Only one BPA oversight visit will be required during the three-year CRC rate period (unless the utility requests a more frequent review).

- Third-party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third-party) is allowed.

- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
  - CFL programs
  - Appliance Rebate programs
  - SGC Manufactured Homes program
  - Energy Star New Construction program
  - Other qualifying cost-effective measures and standard offers

However, if small utility customers don't have sufficient opportunities to implement cost-effective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Donations for cost-effective measures to low income weatherization organizations with no cap (e.g., CFLs).

- Purchase of the renewables (with no *pro rata* adjustment if renewables are over subscribed ((i.e., exceed $6M/year cap)) by CRC participants).

- Donations to NEEA (or other organizations that will use BPA's funds to install cost-effective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.

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