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

## 2010 BPA Rate Case
## Wholesale Power Rate Final Proposal

# WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

July 2009

WP-10-FS-BPA-05A

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2010 WHOLESALE POWER RATE DEVELOPMENT DOCUMENTATION

# TABLE OF CONTENTS

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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 |
| ATC | Accrual to Cash |
| 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 ratio 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 (pertains to generation movement) |
| DJ | Dow Jones |
| DO | Debt Optimization |
| DOE | Department of Energy |
| DOP | Debt Optimization Program |

| | |
|---|---|
| DSI | direct-service industrial customer or direct-service industry |
| DSO | Dispatcher Standing Order |
| 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 (pertains to generation movement) |
| 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) |
| kVAr | kilo-volt ampere reactive |
| 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 |
| MVA | mega-volt ampere |
| MVAr | mega-volt 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 (officially 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.

Section 5 contains excerpts of the ASC customer reports.

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).

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# CHAPTER 1: RATE PROCESS MODELING

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## 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-FS-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-FS-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-FS-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-FS-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-FS-BPA-03).

## REVENUE REQUIREMENT STUDY (WP-10-FS-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-FS-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-FS-BPA-04):**

**Secondary Energy Revenue Forecast**

The Risk Analysis Model (RiskMod) is used to forecast the secondary energy revenues, balancing power purchase expenses, and augmentation purchase expenses. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; 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<sup>xmp®</sup> 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-FS-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-FS-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-FS-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-FS-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-FS-BPA-06) and the Loads and Resources Study (WP-10-FS-BPA-01).

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

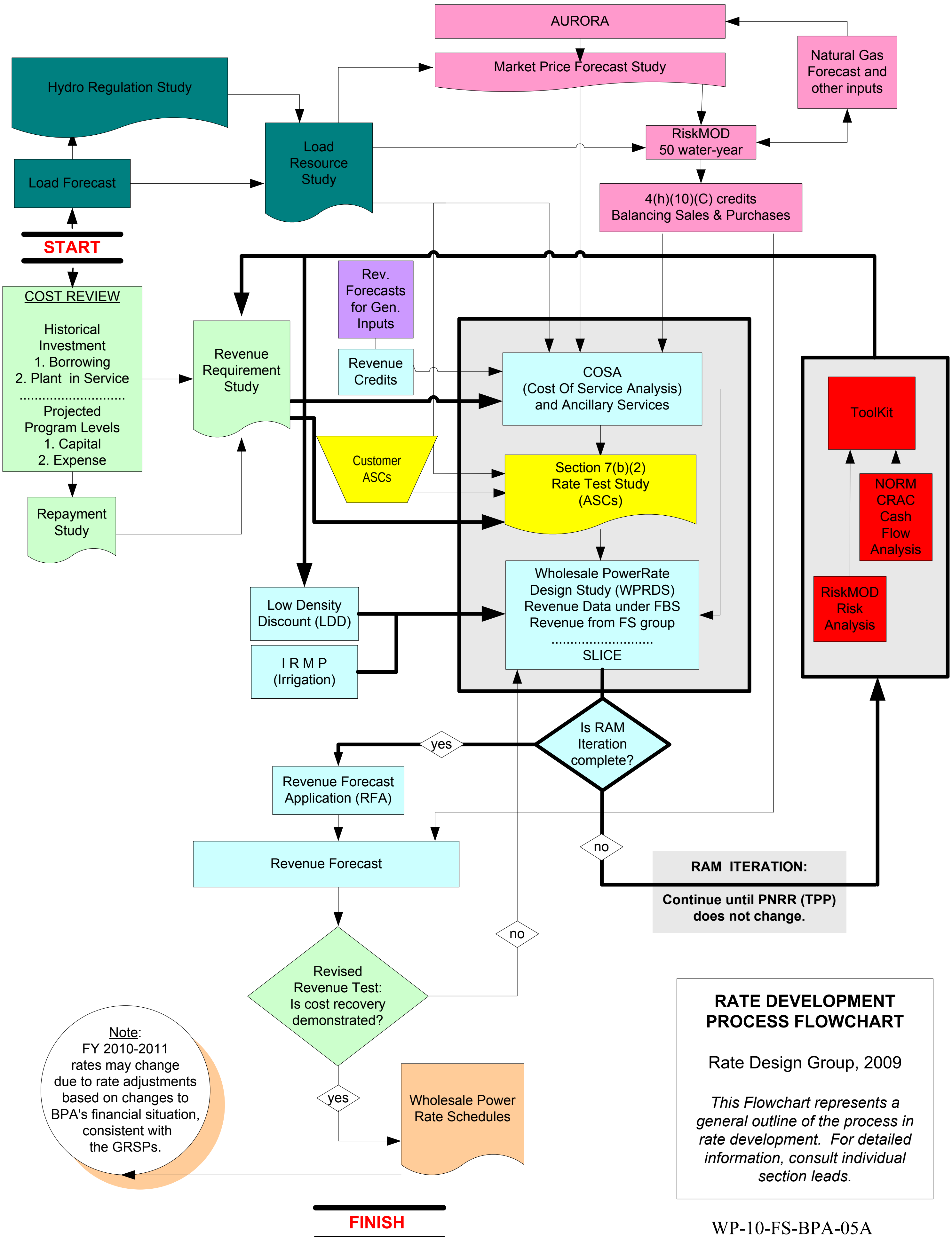
The Rate Design steps of RAM2010 calculate the Program Case for the 7(b)(2) rate test. RAM2010 calculates annual Program Case rates for the rate period and the following four years, pursuant to section 7(b)(2) of the Northwest Power Act and BPA's Legal Interpretation and Implementation Methodology. The 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-FS-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 (version 4.1)




**RATE DEVELOPMENT PROCESS FLOWCHART**

Rate Design Group, 2009

*This Flowchart represents a general outline of the process in rate development. For detailed information, consult individual section leads.*

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# 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 megawatt (MW)/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 MW/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 MW/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 MW/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 FY2010-11)**
*Itemized Revenue Requirement, FY2010-11.*
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 for display purposes. All generation 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 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 2010-11)**
*Calculation of Priority Firm Preference Rate Components, FY2010-11.*
Table calculates Priority Firm Preference rates. The WP-07 Supplemental FY 2009 PF Preference 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 2010-11)**
*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 2.13.1 (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.

**Table 2.13.2 (Final Proposal With/Without 7b3 Allocation to Secondary)**
*Proof That Slice Product Costs are Equitable With/Without 7b3 Allocation to Secondary.*
Table shows the rates and revenues from the Final Proposal and from a scenario of the Final Proposal run with no 7b3 allocation to the secondary revenue credit. The calculations demonstrate that the expected changes to the Slice product costs due to allocating 7b3 costs to secondary are equal to the observed changes in Slice product costs.

# 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.

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## 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 | 2,852 | 3,105 | 3,489 | 3,466 | 3,089 | 3,114 | 2,693 | 2,918 | 2,849 | 2,910 | 3,026 | 2,721 | 61,370 | 7,006 |
| | LLH | 1,844 | 2,306 | 2,503 | 2,555 | 2,091 | 2,050 | 1,799 | 2,146 | 1,852 | 2,109 | 1,978 | 1,906 | | |
| | Demand | 8,204 | 9,117 | 9,680 | 9,970 | 9,492 | 8,646 | 7,495 | 7,677 | 7,252 | 8,010 | 7,686 | 7,359 | | |
| | | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | | |
| **2011** | HLH | 2,837 | 3,190 | 3,517 | 3,496 | 3,114 | 3,143 | 2,648 | 2,847 | 2,777 | 2,934 | 3,100 | 2,745 | 61,447 | 7,014 |
| | LLH | 1,910 | 2,274 | 2,522 | 2,574 | 2,106 | 2,068 | 1,768 | 2,091 | 1,803 | 2,120 | 1,941 | 1,921 | | |
| | Demand | 8,336 | 9,246 | 9,821 | 10,106 | 9,631 | 8,774 | 7,414 | 7,536 | 7,114 | 8,084 | 7,800 | 7,470 | | |

### 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 | 2,158 | 2,354 | 2,733 | 2,713 | 2,461 | 2,451 | 2,177 | 2,068 | 2,111 | 2,195 | 2,280 | 2,085 | 47,058 | 5,372 |
| | LLH | 1,395 | 1,748 | 1,960 | 2,000 | 1,666 | 1,614 | 1,454 | 1,521 | 1,372 | 1,590 | 1,490 | 1,461 | | |
| | Demand | 6,208 | 6,912 | 7,581 | 7,806 | 7,563 | 6,805 | 6,058 | 5,441 | 5,373 | 6,042 | 5,790 | 5,640 | | |
| | | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | | |
| **2011** | HLH | 2,149 | 2,421 | 2,755 | 2,738 | 2,482 | 2,475 | 2,200 | 2,090 | 2,133 | 2,226 | 2,340 | 2,107 | 47,523 | 5,425 |
| | LLH | 1,447 | 1,726 | 1,976 | 2,016 | 1,679 | 1,628 | 1,469 | 1,535 | 1,385 | 1,609 | 1,465 | 1,475 | | |
| | Demand | 6,315 | 7,017 | 7,694 | 7,915 | 7,675 | 6,909 | 6,158 | 5,531 | 5,464 | 6,134 | 5,887 | 5,735 | | |

## Table 2.2

Sales 02

| | | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy GWh | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total PF Exchange Load Forecast FY2010-11** | | | | | | | | | | | | | | | |
| **GWh Energy Sales** | | | | | | | | | | | | | | | |
| **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

| | | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy GWh | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total IP Load Forecast FY2010-11** | | | | | | | | | | | | | | | |
| **GWh Energy Sales** | | | | | | | | | | | | | | | |
| **2010** | HLH | 174 | 154 | 167 | 161 | 154 | 174 | 167 | 161 | 167 | 167 | 167 | 161 | 3522 | 402 |
| | LLH | 125 | 135 | 132 | 138 | 116 | 125 | 122 | 138 | 122 | 132 | 132 | 129 | | |
| | 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 | 167 | 161 | 167 | 161 | 154 | 174 | 167 | 161 | 167 | 161 | 174 | 161 | 3522 | 402 |
| | LLH | 132 | 129 | 132 | 138 | 116 | 125 | 122 | 138 | 122 | 138 | 125 | 129 | | |
| | Demand | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | 402 | | |

Sales 04

| | | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy GWh | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total NR Load Forecast FY2010-11** | | | | | | | | | | | | | | | |
| **GWh Energy Sales** | | | | | | | | | | | | | | | |
| **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 | | |

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 1 | | **Table 2.3.1** | | | | | |
| 2 | | | | | | COSA 06 - FY2010 | |
| 3 | | **COST OF SERVICE ANALYSIS** | | | | | |
| 4 | | **Itemized Revenue Requirement** | | | | | |
| 5 | | **FY 2010** | | | | | |
| 6 | | | | | | | |
| 7 | | **($ 000)** | | | | | |
| 8 | | | | | | | |
| 9 | | **A** | **B** | **C** | **D** | **E** | |
| 10 | | | | | | | |
| 11 | | **INVEST** | **NET** | **NET** | **OPER** | **TOTAL** | |
| 12 | | **BASE** | **INT** | **REVS** | **EXP** | **(B+C+D)** | |
| 13 | 1. GENERATION COSTS | | | | | | |
| 14 | | | | | | | |
| 15 | 2. FEDERAL BASE SYSTEM | | | | | | |
| 16 | 3. HYDRO | 0 | 134,911 | 43,682 | 432,374 | 610,967 | |
| 17 | 4. BPA FISH & WILDLIFE PROGRAM | 204,098 | 17,339 | 5,614 | 248,887 | 271,840 | |
| 18 | 5. TROJAN | | | | 2,200 | 2,200 | |
| 19 | 6. WNP #1 | | | | 166,431 | 166,431 | |
| 20 | 7. WNP #2 | | | | 493,547 | 493,547 | |
| 21 | 8. WNP #3 | | | | 144,892 | 144,892 | |
| 22 | 9. SYSTEM AUGMENTATION | | | | 180,762 | 180,762 | |
| 23 | 10. BALANCING POWER PURCHASES | | | | 87,631 | 87,631 | |
| 24 | 11. TOTAL FEDERAL BASE SYSTEM | 204,098 | 152,250 | 49,296 | 1,756,724 | 1,958,270 | |
| 25 | | | | | | | |
| 26 | 12. NEW RESOURCES | | | | | | |
| 27 | 13. IDAHO FALLS | | | | 4,789 | 4,789 | |
| 28 | 14. COWLITZ FALLS | | | | 14,857 | 14,857 | |
| 29 | 15. OTHER NEW RESOURCES PURCHASES | | | | 62,781 | 62,781 | |
| 30 | 16. TOTAL NEW RESOURCES | | | | 82,427 | 82,427 | |
| 31 | | | | | | | |
| 32 | 17. RESIDENTIAL EXCHANGE | | | | 2,120,999 | 2,120,999 | |
| 33 | | | | | | | |
| 34 | 18. CONSERVATION | | 13,318 | 4,312 | 169,147 | 186,777 | |
| 35 | | | | | | | |
| 36 | 19. OTHER GENERATION COSTS | | | | | | |
| 37 | 20. BPA PROGRAMS | 18,254 | 1,551 | 502 | 138,219 | 140,272 | |
| 38 | 21. WNP #3 PLANT | | | | 0 | 0 | |
| 39 | 22. TOTAL OTHER GENERATION COSTS | 18,254 | 1,551 | 502 | 138,219 | 140,272 | |
| 40 | | | | | | | |
| 41 | 23. TOTAL GENERATION COSTS | 222,352 | 167,119 | 54,110 | 4,267,516 | 4,488,745 | |
| 42 | | | | | | | |
| 43 | 24. TRANSMISSION COSTS | | | | | | |
| 44 | 25. TBL TRANSMISSION/ANCILLARY SERVICES | | | | 125,940 | 125,940 | |
| 45 | 26. 3RD PARTY TRANS/ANCILLARY SERVICES | | | | 1,000 | 1,000 | |
| 46 | 27. GENERAL TRANSFER AGREEMENTS | | | | 50,690 | 50,690 | |
| 47 | 28. TOTAL TRANSMISSION COSTS | | | | 177,630 | 177,630 | |
| 48 | | | | | | | |
| 49 | 29. TOTAL PBL REVENUE REQUIREMENT | | 167,119 | 54,110 | 4,445,147 | 4,666,376 | |
| 50 | 30. BPA TRANSMISSION REVENUE REQUIREMENT | | 130,625 | 77,936 | 602,570 | 811,131 | |
| 51 | (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 |
|---|---|---|---|---|---|
| | **INVEST BASE** | **NET INT** | **NET REVS** | **OPER EXP** | **TOTAL (B+C+D)** |
| 1. GENERATION COSTS | | | | | |
| 2. FEDERAL BASE SYSTEM | | | | | |
| 3. HYDRO | 0 | 138,674 | 37,213 | 447,358 | 623,245 |
| 4. BPA FISH & WILDLIFE PROGRAM | 243,903 | 21,174 | 5,682 | 272,719 | 299,575 |
| 5. TROJAN | | | | 2,300 | 2,300 |
| 6. WNP #1 | | | | 167,977 | 167,977 |
| 7. WNP #2 | | | | 551,051 | 551,051 |
| 8. WNP #3 | | | | 169,093 | 169,093 |
| 9. SYSTEM AUGMENTATION | | | | 273,041 | 273,041 |
| 10. BALANCING POWER PURCHASES | | | | 72,108 | 72,108 |
| 11. TOTAL FEDERAL BASE SYSTEM | 243,903 | 159,848 | 42,895 | 1,955,647 | 2,158,390 |
| 12. NEW RESOURCES | | | | | |
| 13. IDAHO FALLS | | | | 4,789 | 4,789 |
| 14. COWLITZ FALLS | | | | 14,802 | 14,802 |
| 15. OTHER NEW RESOURCES PURCHASES | | | | 62,105 | 62,105 |
| 16. TOTAL NEW RESOURCES | | | | 81,696 | 81,696 |
| 17. RESIDENTIAL EXCHANGE | | | | 2,225,993 | 2,225,993 |
| 18. CONSERVATION | | 12,274 | 3,294 | 176,696 | 192,264 |
| 19. OTHER GENERATION COSTS | | | | | |
| 20. BPA PROGRAMS | 13,577 | 1,179 | 316 | 138,617 | 140,112 |
| 21. WNP #3 PLANT | | | | 0 | 0 |
| 22. TOTAL OTHER GENERATION COSTS | 13,577 | 1,179 | 316 | 138,617 | 140,112 |
| 23. TOTAL GENERATION COSTS | 257,480 | 173,301 | 46,505 | 4,578,649 | 4,798,455 |
| 24. TRANSMISSION COSTS | | | | | |
| 25. TBL TRANSMISSION/ANCILLARY SERVICES | | | | 124,189 | 124,189 |
| 26. 3RD PARTY TRANS/ANCILLARY SERVICES | | | | 1,000 | 1,000 |
| 27. GENERAL TRANSFER AGREEMENTS | | | | 51,340 | 51,340 |
| 28. TOTAL TRANSMISSION COSTS | | | | 176,529 | 176,529 |
| 29. TOTAL PBL REVENUE REQUIREMENT | | 173,301 | 46,505 | 4,755,178 | 4,974,984 |
| 30. BPA TRANSMISSION REVENUE REQUIREMENT (Net of Line 25) | | 145,757 | 73,507 | 644,203 | 863,467 |

| | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | **Table 2.3.3** | | | | | | | |
| 2 | | | | | | | | | | | COSA 07 |
| 3 | **Functionalization of Residential Exchange Costs:** | | | | | | | | | | |
| 4 | | | | | **($ Thousands)** | | | | | | |
| 5 | | | | | | | | | | | |
| 6 | Gross Residential Exchange Cost | | | | $ 4,346,992 | | | | | | |
| 7 | Residential Exchange Transmission | | | | $ 333,515 | | | | | | |
| 8 | Functionalized Residential Exchange Costs | | | | $ 4,013,477 | | | | | | |
| 9 | | | | | | | | | | | |
| 10 | | | | | | | | | | | |
| 11 | | | | | | | | | | | |
| 12 | | | | | | | | | | | |
| 13 | | | | **Table 2.3.4** | | | | | | | |
| 14 | | | | | | | | | | | COSA 08 |
| 15 | | | | **COST OF SERVICE ANALYSIS** | | | | | | | |
| 16 | | | | **Classified Revenue Requirement** | | | | | | | |
| 17 | | | | **Test Period October 2009 - September 2011** | | | | | | | |
| 18 | | | | | | | | | | | |
| 19 | | | | **($ 000)** | | | | | | | |
| 20 | | **Total** | | | | | | | | | |
| 21 | | **Revenue** | | **Energy** | | | **Demand** | | | **Load Variance** | |
| 22 | | **Requirement** | | **Percent** | **Total** | | **Percent** | **Total** | | **Percent** | **Total** |
| 23 | | | | | | | | | | | |
| 24 | 1. GENERATION COSTS | | | | | | | | | | |
| 25 | 2. FEDERAL BASE SYSTEM | | | | | | | | | | |
| 26 | 3. HYDRO | $ 1,234,212 | | 85.66% | $ 1,057,231 | | 13.38% | $ 165,138 | | 0.96% | $ 11,843 |
| 27 | 4. BPA FISH & WILDLIFE PROGRAM | $ 571,415 | | 86.62% | $ 494,959 | | 13.38% | $ 76,456 | | | |
| 28 | 5. TROJAN | $ 4,500 | | 86.62% | $ 3,898 | | 13.38% | $ 602 | | | |
| 29 | 6. WNP #1 | $ 334,408 | | 86.62% | $ 289,664 | | 13.38% | $ 44,744 | | | |
| 30 | 7. WNP #2 | $ 1,044,598 | | 85.66% | $ 894,807 | | 13.38% | $ 139,768 | | 0.96% | $ 10,023 |
| 31 | 8. WNP #3 | $ 313,985 | | 86.62% | $ 271,974 | | 13.38% | $ 42,011 | | | |
| 32 | 9. SYSTEM AUGMENTATION | $ 453,803 | | 85.66% | $ 388,729 | | 13.38% | $ 60,719 | | 0.96% | $ 4,354 |
| 33 | 10. BALANCING POWER PURCHASES | $ 159,738 | | 85.66% | $ 136,833 | | 13.38% | $ 21,373 | | 0.96% | $ 1,533 |
| 34 | 11. TOTAL FEDERAL BASE SYSTEM | $ 4,116,660 | | | $ 3,538,095 | | | $ 550,812 | | | $ 27,753 |
| 35 | | | | | | | | | | | |
| 36 | 12. NEW RESOURCES | | | | | | | | | | |
| 37 | 13. IDAHO FALLS | $ 9,578 | | | | | | $ 1,282 | | | $ 92 |
| 38 | 14. COWLITZ FALLS | $ 29,659 | | 85.66% | $ 25,406 | | 13.38% | $ 3,968 | | 0.96% | $ 285 |
| 39 | 15. OTHER NEW RESOURCES PURCHASES | $ 124,886 | | 85.66% | $ 106,978 | | 13.38% | $ 16,710 | | 0.96% | $ 1,198 |
| 40 | 16. TOTAL NEW RESOURCES | $ 164,123 | | | $ 132,384 | | | $ 21,960 | | | $ 1,575 |
| 41 | | | | | | | | | | | |
| 42 | 17. RESIDENTIAL EXCHANGE | $ 4,013,477 | | 100.00% | $ 4,013,477 | | | | | | |
| 43 | | | | | | | | | | | |
| 44 | 18. CONSERVATION | $ 379,041 | | 86.62% | $ 328,325 | | 13.38% | $ 50,716 | | | |
| 45 | | | | | | | | | | | |
| 46 | 19. OTHER GENERATION COSTS | | | | | | | | | | |
| 47 | 20. BPA PROGRAMS | $ 280,385 | | 85.66% | $ 240,179 | | 13.38% | $ 37,516 | | 0.96% | $ 2,690 |
| 48 | 21. WNP #3 PLANT | $ - | | | | | | $ - | | | |
| 49 | 22. TOTAL OTHER GENERATION COSTS | $ 280,385 | | | $ 240,179 | | | $ 37,516 | | | $ 2,690 |
| 50 | | | | | | | | | | | |
| 51 | 23. TOTAL GENERATION COSTS | $ 8,953,685 | | | $ 8,260,664 | | | $ 661,003 | | | $ 32,018 |
| 52 | | | | | | | | | | | |
| 53 | 24. TRANSMISSION COSTS: | | | | | | | | | | |
| 54 | 25. TBL TRANSMISSION/ANCILLARY SERV | $ 250,130 | | 100.00% | $ 250,130 | | | | | | |
| 55 | 26. 3RD PARTY TRANS/ANCILLARY SERVI | $ 2,000 | | 100.00% | $ 2,000 | | | | | | |
| 56 | 27. GENERAL TRANSFER AGREEMENTS | $ 102,030 | | 100.00% | $ 102,030 | | | | | | |
| 57 | 28. TOTAL TRANSMISSION COSTS | 354,160 | | | 354,160 | | | | | | |
| 58 | | | | | | | | | | | |
| 59 | 29. TOTAL PBL REVENUE REQUIREMENT | $ 9,307,845 | | | $ 8,614,823 | | | $ 693,021 | | | |

## 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 | $ 96,689 | $ 101,969 | $ 198,658 |
| Colville & Spokane Settlements | $ 4,600 | $ 4,600 | $ 9,200 |
| Network Wind Integration&Shaping | $ 1,953 | $ 1,953 | $ 3,906 |
| Misc. Revenues | $ 3,420 | $ 3,420 | $ 6,840 |
| Green Tags | $ 5,040 | $ 5,040 | $ 10,081 |
| Ancillary Product Revenue | $ 90,176 | $ 102,730 | $ 192,906 |
| **Totals** | $ 210,800 | $ 228,633 | $ 439,432 |

## 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 | $ 186,777 | $ 192,264 | $ 379,041 |
| Energy Efficiency Revenues | $ (20,500) | $ (20,500) | $ (41,000) |
| Net Conservation Expense | $ 166,277 | $ 171,764 | $ 338,041 |

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 1 | **Table 2.4.1** | | | | | | |
| 2 | | | | | | | ALLOCATE 01 |
| 3 | | | | | | | |
| 4 | **Energy Allocation Factors with Residential Exchange Included** | | | | | | |
| 5 | **Average Megawatts** | | | | | | |
| 6 | | | | | | | |
| 7 | | | **FY 2010** | **FY 2011** | **Total** | | |
| 8 | | | | | | | |
| 9 | **Total Usage** | | | | | | |
| 10 | Priority Firm.............................. | | 11,772 | 11,833 | 23,605 | | |
| 11 | Industrial Firm........................... | | 413 | 413 | 827 | | |
| 12 | New Resource Firm................... | | 0 | 0 | 0 | | |
| 13 | Surplus Firm Other.................... | | 696 | 666 | 1,362 | | |
| 14 | **Total.........................................** | | **12,881** | **12,912** | **25,793** | | |
| 15 | | | | | | | |
| 16 | **Federal Base System** | | | | | | |
| 17 | Priority Firm.............................. | | 8,205 | 8,181 | 16,387 | | |
| 18 | Industrial Firm........................... | | 0 | 0 | 0 | | |
| 19 | New Resource Firm................... | | 0 | 0 | 0 | | |
| 20 | Surplus Firm Other.................... | | 0 | 0 | 0 | | |
| 21 | **Total.........................................** | | **8,205** | **8,181** | **16,387** | | |
| 22 | | | | | | | |
| 23 | **Residential Exchange** | | | | | | |
| 24 | Priority Firm.............................. | | 3,567 | 3,652 | 7,218 | | |
| 25 | Industrial Firm........................... | | 373 | 371 | 745 | | |
| 26 | New Resource Firm................... | | 0 | 0 | 0 | | |
| 27 | Surplus Firm Other.................... | | 629 | 598 | 1,227 | | |
| 28 | **Total.........................................** | | **4,569** | **4,621** | **9,189** | | |
| 29 | | | | | | | |
| 30 | **New Resource** | | | | | | |
| 31 | Priority Firm.............................. | | 0 | 0 | 0 | | |
| 32 | Industrial Firm........................... | | 40 | 41 | 82 | | |
| 33 | New Resource Firm................... | | 0 | 0 | 0 | | |
| 34 | Surplus Firm Other.................... | | 68 | 67 | 135 | | |
| 35 | **Total.........................................** | | **108** | **108** | **216** | | |
| 36 | | | | | | | |
| 37 | **Conservation** | | | | | | |
| 38 | Priority Firm.............................. | | 11,772 | 11,833 | 23,605 | | |
| 39 | Industrial Firm........................... | | 413 | 413 | 827 | | |
| 40 | New Resource Firm................... | | 0 | 0 | 0 | | |
| 41 | Surplus Firm Other.................... | | 696 | 666 | 1,362 | | |
| 42 | **Total.........................................** | | **12,881** | **12,912** | **25,793** | | |

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 1 | | | **Table 2.4.2** | | | |
| 2 | | | | | | |
| 3 | | | | | | ALLOCATE 02 |
| 4 | | | | | | |
| 5 | | | **Initial Rate Pool Cost Allocations** | | | |
| 6 | | | **($ 000)** | | | |
| 7 | | | | | | |
| 8 | | | **FY 2010** | **FY 2011** | **Total** | |
| 9 | | | | | | |
| 10 | **CLASSES OF SERVICE:** | | | | | |
| 11 | | | | | | |
| 12 | **Priority Firm - Preference** | | | | | |
| 13 | FBS | | $ 1,958,270 | $ 2,158,390 | $ 4,116,660 | |
| 14 | NR | | $ - | $ - | $ - | |
| 15 | Exchange | | $ 1,526,348 | $ 1,626,646 | $ 3,152,994 | |
| 16 | Conservation 1/ | | $ 151,956 | $ 157,410 | $ 309,366 | |
| 17 | BPA programs | | $ 290,523 | $ 290,181 | $ 580,704 | |
| 18 | **Total** | | **$ 3,927,096** | **$ 4,232,627** | **$ 8,159,723** | |
| 19 | | | | | | |
| 20 | **Industrial Firm Power** | | | | | |
| 21 | FBS | | $ - | $ - | $ - | |
| 22 | NR | | $ 30,709 | $ 31,296 | $ 62,005 | |
| 23 | Exchange | | $ 159,768 | $ 165,355 | $ 325,123 | |
| 24 | Conservation 1/ | | $ 5,335 | $ 5,499 | $ 10,834 | |
| 25 | BPA programs | | $ 10,201 | $ 10,136 | $ 20,337 | |
| 26 | **Total** | | **$ 206,013** | **$ 212,286** | **$ 418,299** | |
| 27 | | | | | | |
| 28 | **New Resources Firm** | | | | | |
| 29 | FBS | | $ - | $ - | $ - | |
| 30 | NR | | $ 0.0 | $ 0.0 | $ 0.0 | |
| 31 | Exchange | | $ 0.0 | $ 0.0 | $ 0.1 | |
| 32 | Conservation 1/ | | $ 0.0 | $ 0.0 | $ 0.0 | |
| 33 | BPA programs | | $ 0.0 | $ 0.0 | $ 0.0 | |
| 34 | **Total** | | **$ 0.1** | **$ 0.1** | **$ 0.1** | |
| 35 | | | | | | |
| 36 | **Surplus Firm Power** | | | | | |
| 37 | FBS | | $ - | $ - | $ - | |
| 38 | NR | | $ 51,718 | $ 50,400 | $ 102,118 | |
| 39 | Exchange | | $ 269,066 | $ 266,294 | $ 535,360 | |
| 40 | Conservation 1/ | | $ 8,985 | $ 8,855 | $ 17,841 | |
| 41 | BPA programs | | $ 17,179 | $ 16,324 | $ 33,503 | |
| 42 | **Total** | | **$ 346,948** | **$ 341,874** | **$ 688,822** | |
| 43 | | | | | | |
| 44 | | **Grand Total** | **$ 4,480,058** | **$ 4,786,787** | **$ 9,266,845** | |
| 45 | | | | | | |
| 46 | 1/ Note: Conservation expense from COSA 06 Tables reduced by EE Revenues in Table COSA 09A. | | | | | |

## Table 2.5.1

RDS 05

**RATE DESIGN STUDY**
**Average Cost of Nonfirm Energy**
**Test Period October 2009 - September 2011**

| | | |
|---|---|---|
| Generation Costs: | | **($ 000)** |
| Federal Base System | $ | 4,116,660 |
| New Resources | $ | 164,123 |
| Exchange | $ | 4,013,477 |
| Conservation and EE | $ | 379,041 |
| BPA Programs | $ | 280,385 |
| **Total Generation Costs** | **$** | **8,953,685** |
| Transmission Costs For Firm Power | $ | 990,747 |
| Transmission Costs For Nonfirm Pwr | $ | 250,130 |
| **Total Costs** | **$** | **10,194,562** |
| | | |
| Firm Power Sales: | | **(GWh)** |
| Priority Firm | | 201,106 |
| Industrial Power/Variable Industrial | | 7,043 |
| New Resources | | 0.002 |
| Other Obligations | | 22,445 |
| FPS Pre-Sub., Slice Block, Rate Mitigation Contract Sales | | 3,313 |
| **Total Firm** | | **233,908** |
| Projected Trading Flr Sales | | 39,006 |
| **Total Sales** | | **272,914** |
| | | |
| Average Cost of Nonfirm (mills/kwh) | | 37.35 |

## Table 2.5.2

RDS 06

**RATE DESIGN STUDY**
**Bonneville Average System Cost (BASC)**
**Test Period October 2009 - September 2011**

| | | |
|---|---|---|
| Revenue Requirement: | | **($ Thousands)** |
| Cost of Service Analysis | $ | 11,315,957 |
| Applicable Revenue Credits | $ | (283,621) |
| **Total** | **$** | **11,032,336** |
| | | |
| Sales: | | **(GWh)** |
| Firm Power | | 233,908 |
| Nonfirm Energy | | 39,006 |
| **Total** | | **272,914** |
| | | |
| Bonneville Average System Cost (mills/kwh): | | 40.42 |

RDS 11

# Table 2.5.3

**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** | **$** | **703,912** | **$** | **767,646** | **$** | **1,471,558** |
| 7b3 Costs Allocated to Secondary Revenues | **$** | **(186,366)** | **$** | **(187,178)** | **$** | **(373,543)** |
| **Secondary Revenues After 7b3 Allocation** | **$** | **517,547** | **$** | **580,468** | **$** | **1,098,015** |
| **Allocation of Secondary Revenues Credit** | | | | | | |
| Priority Firm...................................................................... | $ | (517,547) | $ | (580,468) | $ | (1,098,015) |
| Industrial Firm.................................................................. | $ | - | $ | - | $ | - |
| New Resource Firm......................................................... | $ | - | $ | - | $ | - |
| Surplus Firm Other.......................................................... | $ | - | $ | - | $ | - |
| Total.................................................................................. | **$** | **(517,547)** | **$** | **(580,468)** | **$** | **(1,098,015)** |

| | | FY 2010 | | FY 2011 | | Total |
|---|---|---|---|---|---|---|
| **Total Other Revenue Credits** | **$** | **210,800** | **$** | **228,633** | **$** | **439,432** |
| **Allocation of Other Revenue Credits** | | | | | | |
| Priority Firm...................................................................... | $ | (210,800) | $ | (228,633) | $ | (439,432) |
| Industrial Firm.................................................................. | $ | - | $ | - | $ | - |
| New Resource Firm......................................................... | $ | - | $ | - | $ | - |
| Surplus Firm Other.......................................................... | $ | - | $ | - | $ | - |
| Total.................................................................................. | **$** | **(210,800)** | **$** | **(228,633)** | **$** | **(439,432)** |

**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 | $ 346,948 | $ 341,874 | $ 688,822 |
| Expected Revenue from FPS contract sales | $ (96,778) | $ (88,437) | $ (185,216) |
| FPS Pre-Sub Contract Revenue | $ (37,228) | $ (34,456) | $ (71,684) |
| (Surplus)/Shortfall | **$ 212,942** | **$ 218,981** | **$ 431,923** |
| | | | |
| Secondary Revenues allocated to FPS | $ - | $ - | $ - |
| Revenue Credits allocated to FPS | $ - | $ - | $ - |
| | | | |
| **FPS (Surplus)/Shortfall** | **$ 212,942** | **$ 218,981** | **$ 431,923** |

**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....................................................... | $ 211,902 | $ 217,878 | $ 429,780 |
| Industrial Firm.................................................... | $ 1,040 | $ 1,103 | $ 2,143 |
| New Resource Firm.......................................... | $ 0 | $ 0 | $ 0 |
| Surplus Firm Other........................................... | $ (212,942) | $ (218,981) | $ (431,923) |
| Total................................................................ | **$ -** | **$ -** | **$ -** |

## Table 2.5.5

RDS 19

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

**($ 000)**

| | FY 2010 | FY 2011 | Total |
|---|---|---|---|
| **Allocation of Revenue Requirement** | | | |
| Priority Firm............................................... | $ 3,927,096 | $ 4,232,627 | $ 8,159,723 |
| Industrial Firm............................................ | $ 206,013 | $ 212,286 | $ 418,299 |
| New Resource Firm.................................... | $ 0.0512 | $ 0.0528 | $ 0.1041 |
| Surplus Firm Other..................................... | $ 346,948 | $ 341,874 | $ 688,822 |
| **Total..........................................................** | **$ 4,480,058** | **$ 4,786,787** | **$ 9,266,845** |
| | | | |
| **Allocation of Secondary Revenues Credit** | | | |
| Priority Firm............................................... | $ (517,547) | $ (580,468) | $ (1,098,015) |
| Industrial Firm............................................ | $ - | $ - | $ - |
| New Resource Firm.................................... | $ - | $ - | $ - |
| Surplus Firm Other..................................... | $ - | $ - | $ - |
| **Total..........................................................** | **$ (517,547)** | **$ (580,468)** | **$ (1,098,015)** |
| | | | |
| **Allocation of other Revenues Credits** | | | |
| Priority Firm............................................... | $ (210,800) | $ (228,633) | $ (439,432) |
| Industrial Firm............................................ | $ - | $ - | $ - |
| New Resource Firm.................................... | $ - | $ - | $ - |
| Surplus Firm Other..................................... | $ - | $ - | $ - |
| **Total..........................................................** | **$ (210,800)** | **$ (228,633)** | **$ (439,432)** |
| | | | |
| **Allocation of FPS (Surplus)/Shortfall** | | | |
| Priority Firm............................................... | $ 211,902 | $ 217,878 | $ 429,780 |
| Industrial Firm............................................ | $ 1,040 | $ 1,103 | $ 2,143 |
| New Resource Firm.................................... | $ 0.00 | $ 0.00 | $ 0.00 |
| Surplus Firm Other..................................... | $ (212,942) | $ (218,981) | $ (431,923) |
| **Total..........................................................** | **$ -** | **$ -** | **$ -** |
| | | | |
| **Low Density Discount Expenses.......** | | | |
| Priority Firm............................................... | $ 26,419 | $ 26,465 | $ 52,884 |
| | | | |
| **Irrigation Rate Mitigation...................** | | | |
| Priority Firm............................................... | $ 12,036 | $ 12,036 | $ 24,072 |
| | | | |
| **Initial Allocation to Rate Pools..........** | | | |
| Priority Firm............................................... | $ 3,449,107 | $ 3,679,905 | $ 7,129,012 |
| Industrial Firm............................................ | $ 207,053 | $ 213,389 | $ 420,442 |
| New Resource Firm.................................... | $ 0.0515 | $ 0.0531 | $ 0.1046 |
| Surplus Firm Other..................................... | $ 134,007 | $ 122,893 | $ 256,899 |
| **Total..........................................................** | **$ 3,790,167** | **$ 4,016,187** | **$ 7,806,354** |

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | **Table 2.5.6** | | | | |
| 2 | | | | | | | | RDS 21 |
| 3 | | | | **Rate Design Study** | | | | |
| 4 | | | | **7(c)(2) Delta Calculation** | | | | |
| 5 | | | | **Test Period October 2009 - September 2011** | | | | |
| 6 | | | | | | | | |
| 7 | | | | **FY 2010** | **FY 2011** | **Total** | | |
| 8 | | | | | | | | |
| 9 | 1 | IP Allocated Costs | | $ 207,053 | $ 213,389 | $ 420,442 | | |
| 10 | 2 | IP Revenues @ Net Margin | | $ (578) | $ (578) | $ (1,155) | | |
| 11 | 3 | adjustment | | $ (1,047) | $ (945) | $ (1,992) | | |
| 12 | 4 | IP Marginal Cost Rate Revenues | | $ 151,581 | $ 151,581 | $ 303,162 | | |
| 13 | 5 | PF Marginal Cost Rate Revenues | | $ 4,458,119 | $ 4,484,242 | $ 8,942,361 | | |
| 14 | 6 | PF Allocated Energy Costs | | $ 3,449,107 | $ 3,679,905 | $ 7,129,012 | | |
| 15 | 7 | Numerator: 1-2-3-((4/5)*6) | | $ 91,404 | $ 90,519 | $ 181,924 | | |
| 16 | 8 | | | | | | | |
| 17 | 9 | PF Allocation Factor for Delta | | 12,148 | 12,311 | 24,459 | | |
| 18 | 10 | NR Allocation Factor for Delta | | 0.0001 | 0.0001 | 0.0002 | | |
| 19 | 11 | Total Allocation Factors for Delta | | 12,148 | 12,311 | 24,459 | | |
| 20 | 12 | Denominator: 1.0 + ((9/11)*(4/5)) | | 1.034 | 1.034 | 1.034 | | |
| 21 | 13 | | | | | | | |
| 22 | 14 | DELTA: (Numerator / Denominator) | | **$ 88,399** | **$ 87,560** | **$ 175,958** | | |
| 23 | | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | | | | | | | | |
| 27 | | | | **Rate Design Study** | | | | |
| 28 | | | | **7(c)(2) Delta allocation** | | | | |
| 29 | | | | **Test Period October 2009 - September 2011** | | | | |
| 30 | | | | | | | | |
| 31 | | | | **FY 2010** | **FY 2011** | **Total** | | |
| 32 | | | | | | | | |
| 33 | | **IP-PF Link Allocations:......................** | | | | | | |
| 34 | | Priority Firm.......................................... | | $ 88,399 | $ 87,560 | 175,958 | | |
| 35 | | Industrial Firm....................................... | | $ (88,399) | $ (87,560) | (175,958) | | |
| 36 | | New Resource Firm............................... | | $ 0.0008 | $ 0.0008 | $ 0.0015 | | |
| 37 | | Surplus Firm Other................................ | | $ - | $ - | - | | |
| 38 | | **Total.....................................................** | | **$ (0.000)** | **$ (0.000)** | **(0.000)** | | |
| 39 | | | | | | | | |
| 40 | | | | | | | | |
| 41 | | **Allocation to Rate Pools after Link.........................................** | | | | | | |
| 42 | | Priority Firm Preference........................ | | $ 2,164,595 | $ 2,296,327 | $ 4,460,922 | | |
| 43 | | Priority Firm Exchange.......................... | | $ 1,372,911 | $ 1,471,138 | $ 2,844,048 | | |
| 44 | | Industrial Firm....................................... | | $ 118,655 | $ 125,830 | $ 244,484 | | |
| 45 | | New Resource Firm............................... | | $ 0.0523 | $ 0.0538 | $ 0.1061 | | |
| 46 | | Surplus Firm Other................................ | | $ 134,007 | $ 122,893 | $ 256,899 | | |
| 47 | | **Total.....................................................** | | **$ 3,790,167** | **$ 4,016,187** | **$ 7,806,354** | | |
| 48 | | | | | | | | |

# 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 | 4,091 | 2,952 | 9,648 | 7,043 |
| 2 | IP-83 Rates | 4.62 | 2.21 | 14.70 | 12.20 | 7.34 | |
| 3 | Revenue | 18,572 | 12,438 | 60,134 | 36,018 | 70,816 | 197,979 |
| 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] | 28.11 | | | | | |
| 20 | Floor Rate (mills/kWh)[8] | 20.98 | | | | | |

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 | | | | 7,043 | | |
| 2 Floor Rate (mills/kWh) | | | | 20.98 | | |
| 3 Value of Reserves Credit (mills/kWh) | | | | | | |
| 4 Revenue at Floor Rate Less VOR Credit | | | | 147,778 | 147,778 | 20.98 |
| 5 IP Revenue Under Proposed Rates | 0 | 0 | 17,929 | 225,790 | 243,719 | 34.60 |
| 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** 8.17

| | FY 2010 | FY 2011 | Total |
|---|---|---|---|
| Total PF Preference Load (GWH) | 61370 | 61447 | 122816 |
| PF Preference Protection Amount | $ 501,392 | $ 502,018 | $ 1,003,410 |

## 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...................................... | $ (501,392) | $ (502,018) | $ (1,003,410) |
| Priority Firm Exchange....................................... | $ 288,890 | $ 288,989 | $ 577,879 |
| Industrial Firm..................................................... | $ 26,136 | $ 25,852 | $ 51,988 |
| New Resource Firm............................................. | $ 0.0065 | $ 0.0064 | $ 0.0129 |
| Surplus Firm Other.............................................. | $ - | $ - | $ - |
| Reduction in Secondary Revenue Credit ............. 1/ | $ 186,366 | $ 187,178 | $ 373,543 |
| Total.................................................................... | $ - | $ - | $ - |
| | | | |
| **Allocation to Rate Pools after 7b2...................** | | | |
| Priority Firm Preference...................................... | $ 1,663,202 | $ 1,794,309 | $ 3,457,511 |
| Priority Firm Exchange....................................... | $ 1,661,801 | $ 1,760,126 | $ 3,421,927 |
| Industrial Firm..................................................... | $ 144,791 | $ 151,682 | $ 296,472 |
| New Resource Firm............................................. | $ 0.0588 | $ 0.0603 | $ 0.1191 |
| Surplus Firm Other.............................................. | $ 134,007 | $ 122,893 | $ 256,899 |
| Total.................................................................... | $ 3,603,801 | $ 3,829,009 | $ 7,432,810 |

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 | $ 118,655 | $ 125,830 | $ 244,484 |
| 2 IP share of 7b2 adjustment | $ 26,136 | $ 25,852 | $ 51,988 |
| 3 Total IP revenue requirement | $ 144,791 | $ 151,682 | $ 296,472 |
| 4 | | | |
| 5 IP revenues at PF preference rate | $ 91,272 | $ 98,267 | $ 189,539 |
| 6 IP Revenues @ Net Margin | $ (578) | $ (578) | $ (1,155) |
| 7 IP share of 7b2 adjustment | $ 26,136 | $ 25,852 | $ 51,988 |
| 8 Total IP revenue requirement | $ 116,830 | $ 123,541 | $ 240,372 |
| DELTA: (3 - 8) | $ 27,961 | $ 28,140 | $ 56,101 |

| | FY 2010 | FY 2011 | Total |
|---|---|---|---|
| **IP-PF Linc 2 Allocation......................................................** | | | |
| Priority Firm Preference........................................................ | $ - | $ - | |
| Priority Firm Exchange.......................................................... | $ 27,961 | $ 28,140 | $ 56,101 |
| Industrial Firm...................................................................... | $ (27,961) | $ (28,140) | $ (56,101) |
| New Resource Firm.............................................................. | $ 0.0006 | $ 0.0006 | $ 0.0013 |
| Surplus Firm Other................................................................ | $ - | $ - | $ - |
| Total...................................................................................... | $ (0) | $ (0) | $ (0) |
| **Allocation to Rate Pools after IP-PF Linc 2......................** | | | |
| Priority Firm Preference........................................................ | $ 1,663,202 | $ 1,794,309 | $ 3,457,511 |
| Priority Firm Exchange.......................................................... | $ 1,689,762 | $ 1,788,266 | $ 3,478,028 |
| Industrial Firm...................................................................... | $ 116,830 | $ 123,541 | $ 240,372 |
| New Resource Firm.............................................................. | $ 0.0594 | $ 0.0609 | $ 0.1203 |
| Surplus Firm Other................................................................ | $ 134,007 | $ 122,893 | $ 256,899 |
| Total...................................................................................... | $ 3,603,801 | $ 3,829,009 | $ 7,432,810 |

| | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Table 2.6.1** | | | | | | | |
| 2 | | | | | | SLICESEP 01 | | | |
| 3 | | **Rate Design Study** | | | | | | | |
| 4 | | **Slice PF Product Separation** | | | | | | | |
| 5 | | **Test Period October 2009 - September 2011** | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | **FY 2010** | **FY 2011** | **Total** | | | |
| 8 | | | | | | | | | |
| 9 | | **Slice Revenue requirement.........................................................** | | $ 566,071 | $ 605,258 | $ 1,171,329 | | | |
| 10 | | **Slice Revenue Credits...................................................................** | | $ (50,756) | $ (54,791) | $ (105,546) | | | |
| 11 | | **Net Slice PF Product Revenue Requirement** | | $ 515,316 | $ 550,467 | $ 1,065,783 | | | |
| 12 | | | | | | | | | |
| 13 | | **Slice Implementation Expenses ..................................................** | | $ 2,830 | $ 2,830 | $ 5,660 | | | |
| 14 | | | | | | | | | |
| 15 | | **Amount to Allocate** | | $ 515,316 | $ 550,467 | $ 1,065,783 | | | |
| 16 | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | | **Allocation of Slice Revenues..................................................................** | | | | | | | |
| 21 | | | | | | | | | |
| 22 | | Priority Firm Preference........................................................................... | | $ (515,316) | $ (550,467) | $ (1,065,783) | | | |
| 23 | | Priority Firm Exchange............................................................................. | | $ - | $ - | $ - | | | |
| 24 | | Industrial Firm.......................................................................................... | | $ - | $ - | $ - | | | |
| 25 | | New Resource Firm.................................................................................. | | $ - | $ - | $ - | | | |
| 26 | | Surplus Firm Other................................................................................... | | $ - | $ - | $ - | | | |
| 27 | | Total.......................................................................................................... | | $ (515,316) | $ (550,467) | $ (1,065,783) | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | | **Slice Secondary Revenue Credit Adjustment** | | $ 159,280 | $ 173,701 | $ 332,981 | | | |
| 34 | | | | | | | | | |
| 35 | | Priority Firm Preference........................................................................... | | $ 159,280 | $ 173,701 | $ 332,981 | | | |
| 36 | | Priority Firm Exchange............................................................................. | | $ - | $ - | $ - | | | |
| 37 | | Industrial Firm.......................................................................................... | | $ - | $ - | $ - | | | |
| 38 | | New Resource Firm.................................................................................. | | $ - | $ - | $ - | | | |
| 39 | | Surplus Firm Other................................................................................... | | $ - | $ - | $ - | | | |
| 40 | | Total.......................................................................................................... | | $ 159,280 | $ 173,701 | $ 332,981 | | | |
| 41 | | | | | | | | | |
| 42 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | **FY 2010** | **FY 2011** | **Total** | | | |
| 56 | | **Allocation to Rate Pools after Slice Separation Step............................** | | | | | | | |
| 57 | | Priority Firm Preference........................................................................... | | $ 1,307,167 | $ 1,417,543 | $ 2,724,709 | | | |
| 58 | | Priority Firm Exchange............................................................................. | | $ 1,689,762 | $ 1,788,266 | $ 3,478,028 | | | |
| 59 | | Industrial Firm.......................................................................................... | | $ 116,830 | $ 123,541 | $ 240,372 | | | |
| 60 | | New Resource Firm.................................................................................. | | $ 0.0594 | $ 0.0609 | $ 0.1203 | | | |
| 61 | | Surplus Firm Other................................................................................... | | $ 134,007 | $ 122,893 | $ 256,899 | | | |
| 62 | | Total.......................................................................................................... | | $ 3,247,765 | $ 3,452,243 | $ 6,700,009 | | | |
| 63 | | | | | | | | | |
| 64 | | | | | | | | | |

## 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 | $ 207,053 | $ 213,389 | $ 420,442 |
| 2 | IP Revenues @ Net Margin | $ 25,552 | $ 29,369 | $ 54,922 |
| 3 | adjustment | $ 25,216 | $ 16,217 | $ 41,433 |
| 4 | IP Marginal Cost Rate Revenues | $ 151,581 | $ 151,581 | $ 303,162 |
| 5 | PF Marginal Cost Rate Revenues | $ 1,252,800 | $ 1,266,362 | $ 2,519,162 |
| 6 | PF Allocated Energy Costs | $ 1,307,167 | $ 1,417,543 | $ 2,724,709 |
| 7 | Numerator: 1-2-3-((4/5)*6) | (1,873) | (1,875) | (3,810) |
| 8 | | | | |
| 9 | PF Allocation Factor for Delta | 5,523 | 5,578 | 11,101 |
| 10 | NR Allocation Factor for Delta | 0.0001 | 0.0001 | 0.0002 |
| 11 | Total Allocation Factors for Delta | 5,523 | 5,578 | 11,101 |
| 12 | Denominator: 1.0 + ((9/11)*(4/5)) | 1.1210 | 1.1197 | 1.1203 |
| 13 | | | | |
| 14 | DELTA: (Numerator / Denominator) | (1,671) | (1,674) | (3,346) |

**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........................................... | $ (1,671) | $ (1,674) | $ (3,346) |
| Industrial Firm........................................ | $ 1,671 | $ 1,674 | $ 3,346 |
| New Resource Firm................................ | $ - | $ - | $ - |
| Surplus Firm Other................................. | $ - | $ - | $ - |
| Total....................................................... | $ - | $ - | $ - |

| | FY 2010 | FY 2011 | Total |
|---|---|---|---|
| **Allocation to Rate Pools after Link 3.....................................** | | | |
| Priority Firm Preference.......................... | $ 1,305,495 | $ 1,415,868 | $ 2,721,364 |
| Priority Firm Exchange........................... | $ 1,689,762 | $ 1,788,266 | $ 3,478,028 |
| Industrial Firm........................................ | $ 118,502 | $ 125,216 | $ 243,717 |
| New Resource Firm................................ | $ 0.0594 | $ 0.0609 | $ 0.1203 |
| Surplus Firm Other................................. | $ 134,007 | $ 122,893 | $ 256,899 |
| Total....................................................... | $ 3,247,765 | $ 3,452,243 | $ 6,700,009 |

# Table 2.7

PF 2010-11

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

**PF PREFERENCE RATE SHAPE**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Mills/kwh | | | | | | | | | | | | |
| HLH | 29.21 | 31.15 | 32.51 | 27.60 | 28.19 | 26.15 | 24.54 | 20.50 | 18.55 | 22.85 | 26.76 | 27.62 |
| LLH | 21.40 | 22.72 | 23.85 | 19.96 | 20.16 | 19.17 | 17.64 | 14.17 | 9.85 | 16.73 | 19.85 | 22.17 |
| MONTHLY DEMAND | 1.91 | 2.04 | 2.14 | 1.82 | 1.85 | 1.72 | 1.62 | 1.34 | 1.23 | 1.50 | 1.76 | 1.82 |

LV Rate 0.46

**PF billing determinants (GWHs)**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | 4,307 | 4,775 | 5,488 | 5,452 | 4,943 | 4,926 | 4,377 | 4,158 | 4,244 | 4,421 | 4,619 | 4,193 | 94582 | 31527 | 3599 |
| LLH | 2,843 | 3,474 | 3,936 | 4,016 | 3,345 | 3,242 | 2,923 | 3,055 | 2,757 | 3,199 | 2,955 | 2,935 | | | |
| Demand | 12,523 | 13,929 | 15,274 | 15,721 | 15,239 | 13,714 | 12,216 | 10,973 | 10,836 | 12,176 | 11,677 | 11,375 | | | |
| | | | | | | | | | | LV Billing Determinant | | | 69605257 | | |

**Revenue At Marginal Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Maginal Revenues | Allocated Costs | Rate Factor |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | $ 125,803 | $ 148,755 | $ 178,409 | $ 150,466 | $ 139,332 | $ 128,826 | $ 107,400 | $ 85,243 | $ 78,723 | $ 101,020 | $ 123,611 | $ 115,802 | $ 2,226,016 | $ 2,393,789 | 107.53% |
| LLH | $ 60,830 | $ 78,929 | $ 93,870 | $ 80,157 | $ 67,427 | $ 62,143 | $ 51,560 | $ 43,296 | $ 27,153 | $ 53,520 | $ 58,663 | $ 65,076 | | | |
| Demand | $ 23,919 | $ 28,415 | $ 32,687 | $ 28,612 | $ 28,192 | $ 23,588 | $ 19,791 | $ 14,703 | $ 13,329 | $ 18,264 | $ 20,552 | $ 20,702 | $ 272,753 | $ 293,145 | 107.53% |
| | | | | | | | | | | | | LV Revenue | $ 32,018 | $ 34,429 | 107.53% |
| | | | | | | | | | | | | | $ 2,530,788 | $ 2,721,364 | 107.53% |

| PF rates | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | **31.41** | **33.50** | **34.96** | **29.68** | **30.31** | **28.12** | **26.39** | **22.04** | **19.95** | **24.57** | **28.78** | **29.70** |
| **LLH** | **23.01** | **24.43** | **25.65** | **21.46** | **21.68** | **20.61** | **18.97** | **15.24** | **10.59** | **17.99** | **21.34** | **23.84** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |
| | | | | | | | | | | | **LV Rate** | **0.490** |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | $ 135,278 | $ 159,978 | $ 191,854 | $ 161,806 | $ 149,811 | $ 138,531 | $ 115,496 | $ 91,647 | $ 84,664 | $ 108,624 | $ 132,942 | $ 124,523 | $ 2,393,689 |
| LLH | $ 65,406 | $ 84,870 | $ 100,955 | $ 86,181 | $ 72,511 | $ 66,811 | $ 55,447 | $ 46,566 | $ 29,193 | $ 57,551 | $ 63,067 | $ 69,978 | |
| Demand | $ 25,672 | $ 30,504 | $ 35,131 | $ 30,813 | $ 30,325 | $ 25,371 | $ 21,257 | $ 15,801 | $ 14,304 | $ 19,603 | $ 22,070 | $ 22,295 | $ 293,145 |
| | | | | | | | | | | | | LV Revenue | $ 34,107 |
| | | | | | | | | | | | | | $ 2,720,941 |

**Non-Slice PF Average Rate**

| | | |
|---|---|---|
| **Energy Costs** | **$ 2,393,789** | **25.31** |
| **Demand Costs** | **$ 293,145** | **3.10** |
| **Unbundled Cost** | **$ 34,429** | **0.36** |
| **Total** | **$ 2,721,364** | **28.77** |
| | | |
| **Billing Determinants** | **94582** | |

# Table 2.8

Base PFx 2010-11

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

**LEVELIZED SHAPE OF POWER**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Mills/kwh | | | | | | | | | | | | |
| HLH | 40.32 | 42.10 | 44.52 | 48.58 | 47.65 | 45.40 | 40.71 | 40.03 | 39.39 | 42.11 | 47.13 | 46.09 |
| LLH | 34.12 | 37.37 | 39.33 | 40.73 | 40.08 | 37.99 | 34.05 | 28.16 | 29.42 | 36.21 | 39.66 | 40.76 |
| MONTHLY DEMAND | 2.05 | 2.19 | 2.30 | 1.96 | 1.99 | 1.85 | 1.74 | 1.44 | 1.32 | 1.61 | 1.89 | 1.96 |

**Unbifurcated PF billing determinants (GWHs)**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | 9,268 | 10,365 | 12,243 | 12,738 | 11,623 | 11,325 | 9,952 | 8,834 | 8,195 | 8,345 | 9,437 | 9,516 | 201,106 |
| LLH | 5,921 | 6,921 | 7,970 | 8,920 | 7,637 | 7,179 | 6,205 | 6,161 | 5,054 | 5,643 | 5,578 | 6,079 | |
| Demand | 28,434 | 30,943 | 35,448 | 38,138 | 36,580 | 30,163 | 27,393 | 23,806 | 21,658 | 24,419 | 25,280 | 26,758 | |

**Revenue At Marginal Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Maginal Revenues | Allocated Costs | Rate Factor |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy | $ 575,717 | $ 694,999 | $ 858,590 | $ 982,083 | $ 859,890 | $ 786,920 | $ 616,437 | $ 527,133 | $ 471,513 | $ 555,721 | $ 665,993 | $ 686,361 | $ 8,281,358 | $ 6,643,967 | 80.23% |
| Demand | $ 58,289 | $ 67,766 | $ 81,530 | $ 74,750 | $ 72,794 | $ 55,801 | $ 47,664 | $ 34,281 | $ 28,589 | $ 39,315 | $ 47,778 | $ 52,446 | $ 661,003 | $ 661,003 | 100.00% |
| | | | | | | | | | | | | Transmission Costs | | $ - | |
| | | | | | | | | | | | | | $ 8,942,361 | $ 7,304,970 | |

**Unbifurcated PF**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy** | **30.41** | **32.26** | **34.08** | **36.38** | **35.82** | **34.12** | **30.61** | **28.20** | **28.55** | **31.87** | **35.59** | **35.31** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy | $ 461,886 | $ 557,584 | $ 688,830 | $ 787,905 | $ 689,873 | $ 631,330 | $ 494,555 | $ 422,909 | $ 378,286 | $ 445,844 | $ 534,313 | $ 550,654 | $ 6,643,967 |
| Demand | $ 58,289 | $ 67,766 | $ 81,530 | $ 74,750 | $ 72,794 | $ 55,801 | $ 47,664 | $ 34,281 | $ 28,589 | $ 39,315 | $ 47,778 | $ 52,446 | $ 661,003 |
| | | | | | | | | | | | | Transmission Costs | $ - |
| | | | | | | | | | | | | | $ 7,304,970 |

**Unbifurcated PF Rate**

| | | |
|---|---|---|
| Energy Costs | $ 6,643,967 | 33.04 |
| Demand Costs | $ 661,003 | 3.29 |
| Unbundled Cost | $ - | 0.00 |
| Transmission Costs | $ - | 0.00 |
| Total | $ 7,304,970 | 36.32 |
| Billing Determinants | $ 201,106 | |

| | |
|---|---|
| **Unbifurcated PF** | 36.32 |
| Transmission Costs | 4.26 |
| **Delivered Unbifurcated PF** | **40.58** |

## 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 | $ 47.40 | $ 40.58 | 8020 | $ 54,700 | 4.7% | $ 29,688 | 8020 | $ 3.70 | $ 40.58 | $ 44.28 | $ 25,024 |
| Idaho Power | $ 35.65 | $ 40.58 | 0 | $ - | 0.0% | $ - | 0 | $ - | $ 40.58 | $ 40.58 | $ - |
| Northwestern Energy PNWR | $ 57.57 | $ 40.58 | 1248 | $ 21,198 | 1.8% | $ 11,481 | 1248 | $ 9.20 | $ 40.58 | $ 49.78 | $ 9,720 |
| Pacificorp | $ 56.54 | $ 40.58 | 19170 | $ 305,949 | 26.2% | $ 165,741 | 19170 | $ 8.65 | $ 40.58 | $ 49.23 | $ 140,131 |
| Portland General | $ 56.89 | $ 40.58 | 17588 | $ 286,854 | 24.6% | $ 156,109 | 17588 | $ 8.88 | $ 40.58 | $ 49.46 | $ 130,676 |
| Puget Sound Energy | $ 59.32 | $ 40.58 | 23972 | $ 449,234 | 38.5% | $ 244,907 | 23972 | $ 10.22 | $ 40.58 | $ 50.80 | $ 204,241 |
| Franklin | $ 49.28 | $ 40.58 | 714 | $ 6,216 | 0.5% | $ 3,367 | 714 | $ 4.71 | $ 40.58 | $ 45.29 | $ 2,851 |
| Snohomish | $ 46.12 | $ 40.58 | 7578 | $ 41,982 | 3.6% | $ 22,687 | 7578 | $ 2.99 | $ 40.58 | $ 43.57 | $ 19,324 |
| Total/Average | | | | $ 1,166,133 | 100% | $ 633,980 | | | | $ 48.68 | $ 531,966 |

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 SHAPE OF POWER**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Mills/kwh | | | | | | | | | | | | |
| HLH | 40.32 | 42.10 | 44.52 | 48.58 | 47.65 | 45.40 | 40.71 | 40.03 | 39.39 | 42.11 | 47.13 | 46.09 |
| LLH | 34.12 | 37.37 | 39.33 | 40.73 | 40.08 | 37.99 | 34.05 | 28.16 | 29.42 | 36.21 | 39.66 | 40.76 |
| MONTHLY DEMAND | 2.05 | 2.19 | 2.30 | 1.96 | 1.99 | 1.85 | 1.74 | 1.44 | 1.32 | 1.61 | 1.89 | 1.96 |

**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 | $ 218,275 | $ 258,782 | $ 349,019 | $ 435,019 | $ 396,115 | $ 346,363 | $ 277,517 | $ 177,020 | $ 142,356 | $ 156,510 | $ 221,837 | $ 278,465 | $ 3,257,277 | $ 3,196,685 | 98.14% |
| Demand | $ 24,381 | $ 27,551 | $ 36,680 | $ 35,402 | $ 34,738 | $ 23,575 | $ 21,722 | $ 12,373 | $ 9,627 | $ 13,403 | $ 18,510 | $ 23,381 | $ 281,343 | $ 281,343 | 100.00% |
| | | | | | | | | | | | | Transmission Costs | $ 333,515 | $ 333,515 | 100.00% |
| | | | | | | | | | | | | | $ 3,872,135 | $ 3,811,543 | |

| PF exchange rates | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy** | **37.27** | **39.62** | **41.86** | **44.62** | **43.88** | **41.82** | **37.57** | **34.80** | **35.21** | **39.24** | **43.81** | **43.36** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy | $ 214,215 | $ 253,968 | $ 342,527 | $ 426,927 | $ 388,746 | $ 339,920 | $ 272,355 | $ 173,727 | $ 139,708 | $ 153,598 | $ 217,711 | $ 273,285 | $ 3,196,685 |
| Demand | $ 24,381 | $ 27,551 | $ 36,680 | $ 35,402 | $ 34,738 | $ 23,575 | $ 21,722 | $ 12,373 | $ 9,627 | $ 13,403 | $ 18,510 | $ 23,381 | $ 281,343 |
| | | | | | | | | | | | | Transmission Costs | $ 333,515 |
| | | | | | | | | | | | | | $ 3,811,543 |

**PF Exchange Average Rate**

| | | |
|---|---|---|
| Energy Costs | $ 3,196,685 | 40.83 |
| Demand Costs | $ 281,343 | 3.59 |
| Unbundled Cost | $ - | 0.00 |
| Transmission Costs | $ 333,515 | 4.26 |
| Total | $ 3,811,543 | 48.68 |
| Billing Determinants | 78,290 | |

# Table 2.10

IP 2010-11

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

**LEVELIZED SHAPE OF POWER**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy Mills/kwh** | | | | | | | | | | | | |
| HLH | 40.32 | 42.10 | 44.52 | 48.58 | 47.65 | 45.40 | 40.71 | 40.03 | 39.39 | 42.11 | 47.13 | 46.09 |
| LLH | 34.12 | 37.37 | 39.33 | 40.73 | 40.08 | 37.99 | 34.05 | 28.16 | 29.42 | 36.21 | 39.66 | 40.76 |
| **MONTHLY DEMAND** | 2.05 | 2.19 | 2.30 | 1.96 | 1.99 | 1.85 | 1.74 | 1.44 | 1.32 | 1.61 | 1.89 | 1.96 |

**IP billing determinants (GWHs)**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total Energy |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | 340.90 | 315.17 | 334.46 | 321.60 | 308.74 | 347.33 | 334.46 | 321.60 | 334.46 | 328.03 | 340.90 | 321.60 | 7,043.04 |
| LLH | 257.28 | 264.52 | 263.71 | 276.58 | 231.55 | 250.04 | 244.42 | 276.58 | 244.42 | 270.14 | 257.28 | 257.28 | |
| 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 | $ 13,744 | $ 13,269 | $ 14,892 | $ 15,623 | $ 14,711 | $ 15,770 | $ 13,616 | $ 12,874 | $ 13,176 | $ 13,814 | $ 16,067 | $ 14,824 | $ 285,233 | $ 225,788 | 79.16% |
| LLH | $ 8,778 | $ 9,885 | $ 10,372 | $ 11,264 | $ 9,281 | $ 9,500 | $ 8,323 | $ 7,788 | $ 7,191 | $ 9,782 | $ 10,204 | $ 10,486 | | | |
| Demand | $ 1,648 | $ 1,761 | $ 1,849 | $ 1,576 | $ 1,600 | $ 1,487 | $ 1,399 | $ 1,158 | $ 1,061 | $ 1,294 | $ 1,520 | $ 1,576 | $ 17,929 | $ 17,929 | 100.00% |
| | | | | | | | | | | | | | $ 303,162 | $ 243,717 | |

| IP rates | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | **31.92** | **33.33** | **35.24** | **38.46** | **37.72** | **35.94** | **32.23** | **31.69** | **31.18** | **33.33** | **37.31** | **36.49** |
| **LLH** | **27.01** | **29.58** | **31.13** | **32.24** | **31.73** | **30.08** | **26.95** | **22.29** | **23.29** | **28.66** | **31.40** | **32.26** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HLH | $ 10,881 | $ 10,505 | $ 11,787 | $ 12,369 | $ 11,646 | $ 12,483 | $ 10,780 | $ 10,192 | $ 10,429 | $ 10,933 | $ 12,719 | $ 11,735 | $ 225,790 |
| LLH | $ 6,949 | $ 7,824 | $ 8,209 | $ 8,917 | $ 7,347 | $ 7,521 | $ 6,587 | $ 6,165 | $ 5,692 | $ 7,742 | $ 8,079 | $ 8,300 | |
| Demand | $ 1,648 | $ 1,761 | $ 1,849 | $ 1,576 | $ 1,600 | $ 1,487 | $ 1,399 | $ 1,158 | $ 1,061 | $ 1,294 | $ 1,520 | $ 1,576 | $ 17,929 |
| | | | | | | | | | | | | | $ 243,719 |

**IP Average Rate**

| | | |
|---|---|---|
| Energy Costs | $ 225,788.0 | 32.06 |
| Demand Costs | $ 17,929.2 | 2.55 |
| Unbundled Cost | $ - | 0.00 |
| Total | $ 243,717.2 | 34.60 |
| Non-Slice Billing Determinants | $ 7,043.0 | |

# Table 2.11

NR 2010-11

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

**LEVELIZED SHAPE OF POWER**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy Mills/kwh** | | | | | | | | | | | | |
| **HLH** | 40.32 | 42.10 | 44.52 | 48.58 | 47.65 | 45.40 | 40.71 | 40.03 | 39.39 | 42.11 | 47.13 | 46.09 |
| **LLH** | 34.12 | 37.37 | 39.33 | 40.73 | 40.08 | 37.99 | 34.05 | 28.16 | 29.42 | 36.21 | 39.66 | 40.76 |
| **MONTHLY DEMAND** | 2.05 | 2.19 | 2.30 | 1.96 | 1.99 | 1.85 | 1.74 | 1.44 | 1.32 | 1.61 | 1.89 | 1.96 |

**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 | 0.00009 | 0.00008 | 0.00008 | 0.00008 | 0.00008 | 0.00008 | 0.00008 | 0.002 |
| **LLH** | 0.00006 | 0.00007 | 0.00007 | 0.00007 | 0.00006 | 0.00006 | 0.00006 | 0.00007 | 0.00006 | 0.00007 | 0.00006 | 0.00006 | |
| **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 | $ 0.004 | $ 0.004 | $ 0.004 | $ 0.004 | $ 0.003 | $ 0.003 | $ 0.003 | $ 0.003 | $ 0.004 | $ 0.004 | $ 0.071 | $ 0.116 | 163.27% |
| **LLH** | $ 0.002 | $ 0.002 | $ 0.003 | $ 0.003 | $ 0.002 | $ 0.002 | $ 0.002 | $ 0.002 | $ 0.002 | $ 0.002 | $ 0.003 | $ 0.003 | | | |
| **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 | $ 0.004 | $ 0.004 | 100.00% |
| | | | | | | | | | | | | | $ 0.075 | $ 0.120 | |

| **NR rates** | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | **65.83** | **68.74** | **72.70** | **79.32** | **77.80** | **74.13** | **66.47** | **65.36** | **64.32** | **68.76** | **76.95** | **75.26** |
| **LLH** | **55.71** | **61.02** | **64.22** | **66.49** | **65.44** | **62.03** | **55.60** | **45.98** | **48.04** | **59.12** | **64.76** | **66.54** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | $ 0.006 | $ 0.005 | $ 0.006 | $ 0.006 | $ 0.006 | $ 0.006 | $ 0.006 | $ 0.005 | $ 0.005 | $ 0.006 | $ 0.007 | $ 0.006 | $ 0.116 |
| **LLH** | $ 0.004 | $ 0.004 | $ 0.004 | $ 0.005 | $ 0.004 | $ 0.004 | $ 0.003 | $ 0.003 | $ 0.003 | $ 0.004 | $ 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 | $ 0.004 |
| | | | | | | | | | | | | | $ 0.120 |

**NR Average Rate**

| | | |
|---|---|---|
| Energy Costs | $ 0.116 | 66.12 |
| Demand Costs | $ 0.004 | 2.55 |
| Unbundled Cost | $ - | 0.00 |
| Total | $ 0.120 | 68.67 |
| | | |
| 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** | **31.41** | **33.50** | **34.96** | **29.68** | **30.31** | **28.12** | **26.39** | **22.04** | **19.95** | **24.57** | **28.78** | **29.70** |
| **LLH** | **23.01** | **24.43** | **25.65** | **21.46** | **21.68** | **20.61** | **18.97** | **15.24** | **10.59** | **17.99** | **21.34** | **23.84** |
| **Demand** | **2.05** | **2.19** | **2.30** | **1.96** | **1.99** | **1.85** | **1.74** | **1.44** | **1.32** | **1.61** | **1.89** | **1.96** |

**Flat Load FY2010-11**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | 340.9 | 315.2 | 334.5 | 321.6 | 308.7 | 347.3 | 334.5 | 321.6 | 334.5 | 328.0 | 340.9 | 321.6 | 7043.0 |
| **LLH** | 257.3 | 264.5 | 263.7 | 276.6 | 231.6 | 250.0 | 244.4 | 276.6 | 244.4 | 270.1 | 257.3 | 257.3 | |
| **Demand** | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | 804.0 | |

**Revenues at Proposed Rates**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HLH** | $ 10,708 | $ 10,558 | $ 11,693 | $ 9,545 | $ 9,358 | $ 9,767 | $ 8,827 | $ 7,088 | $ 6,673 | $ 8,060 | $ 9,811 | $ 9,552 | $ 174,817 |
| **LLH** | $ 5,920 | $ 6,462 | $ 6,764 | $ 5,935 | $ 5,020 | $ 5,153 | $ 4,637 | $ 4,215 | $ 2,588 | $ 4,860 | $ 5,490 | $ 6,134 | |
| **Demand** | $ 1,648 | $ 1,761 | $ 1,849 | $ 1,576 | $ 1,600 | $ 1,487 | $ 1,399 | $ 1,158 | $ 1,061 | $ 1,294 | $ 1,520 | $ 1,576 | $ 17,929 |
| | | | | | | | | | | | | | $ 192,746 |

**Flat PF Preference Rate FY2007-09 $ 27.37**

## Table 2.13.1 (1 of 2)

## Slice Costing Table

| | A | B | F: FY 2010 forecast | H: FY 2011 forecast |
|---|---|---|---|---|
| 7 | 1 | **Operating Expenses** | | |
| 8 | 2 | **Power System Generation Resources** | | |
| 9 | 3 | **Operating Generation** | | |
| 10 | 4 | COLUMBIA GENERATING STATION (WNP-2) | $ 257,811 | $ 324,882 |
| 11 | 5 | BUREAU OF RECLAMATION | $ 87,318 | $ 96,110 |
| 12 | 6 | CORPS OF ENGINEERS | $ 191,060 | $ 192,433 |
| 13 | 7 | LONG-TERM CONTRACT GENERATING PROJECTS | $ 30,455 | $ 30,767 |
| 14 | 8 | **Sub-Total** | **$ 566,644** | **$ 644,192** |
| 15 | 9 | **Operating Generation Settlement Payment** | | |
| 16 | 10 | COLVILLE GENERATION SETTLEMENT | $ 21,328 | $ 21,754 |
| 17 | 11 | **Sub-Total** | **$ 21,328** | **$ 21,754** |
| 18 | 12 | **Non-Operating Generation** | | |
| 19 | 13 | TROJAN DECOMMISSIONING | $ 2,200 | $ 2,300 |
| 20 | 14 | WNP-1&3 DECOMMISSIONING | $ 418 | $ 428 |
| 21 | 15 | **Sub-Total** | **$ 2,618** | **$ 2,728** |
| 22 | 16 | **Contracted Power Purchases** | | |
| 23 | 17 | HEDGING/MITIGATION (omit except for those assoc. with inventory solution) | $ - | $ - |
| 24 | 18 | PNCA HEADWATER BENEFITS | $ 2,042 | $ 2,620 |
| 25 | 19 | GROSS OTHER POWER PURCHASES (short term - omit) | | |
| 26 | 20 | **Sub-Total** | **$ 2,042** | **$ 2,620** |
| 27 | 21 | **Bookout Adjustment to Power Purchases (omit)** | | |
| 28 | 22 | **Augmentation Power Purchases (omit - calculated below)** | | |
| 29 | 23 | AUGMENTATION POWER PURCHASES (omit) | | |
| 30 | 24 | CONSERVATION AUGMENTATION (omit) | | |
| 31 | 25 | **Sub-Total** | $ - | $ - |
| 32 | 26 | **Exchanges and Settlements** | | |
| 33 | 27 | PUBLIC RESIDENTIAL EXCHANGE | $ 12,101 | $ 10,016 |
| 34 | 28 | IOU RESIDENTIAL EXCHANGE | $ 254,770 | $ 258,667 |
| 35 | 29 | OTHER SETTLEMENTS | $ - | $ - |
| 36 | 30 | **Sub-Total** | **$ 266,871** | **$ 268,683** |
| 37 | 31 | **Renewable Generation** | | |
| 38 | 32 | RENEWABLES R&D | $ 6,174 | $ 6,133 |
| 39 | 33 | RENEWABLES CONSERVATION RATE CREDIT | $ 4,000 | $ 2,500 |
| 40 | 34 | RENEWABLES (excludes expenses from reinvested revenues) | $ 30,374 | $ 30,965 |
| 41 | 35 | **Sub-Total** | **$ 40,548** | **$ 39,598** |
| 42 | 36 | **Generation Conservation** | | |
| 43 | 37 | GENERATION CONSERVATION R&D | | |
| 44 | 38 | DSM TECHNOLOGIES | $ - | $ - |
| 45 | 39 | CONSERVATION ACQUISITION | $ 14,000 | $ 14,000 |
| 46 | 40 | LOW INCOME WEATHERIZATION & TRIBAL | $ 5,000 | $ 5,000 |
| 47 | 41 | ENERGY EFFICIENCY DEVELOPMENT | $ 20,500 | $ 20,500 |
| 48 | 42 | LEGACY | $ 1,988 | $ 1,622 |
| 49 | 43 | MARKET TRANSFORMATION | $ 14,500 | $ 14,500 |
| 50 | 44 | **Sub-Total** | **$ 55,988** | **$ 55,622** |
| 51 | 45 | **Conservation and Renewable Discount (C&RD)** | | |
| 52 | 46 | CONSERVATION RATE CREDIT | $ 28,000 | $ 29,500 |
| 53 | 47 | CONSERVATION AND RENEWABLE DISCOUNT | | |
| 54 | 48 | **Sub-Total** | **$ 28,000** | **$ 29,500** |
| 55 | 49 | **Power System Generation Sub-Total** | **$ 984,039** | **$ 1,064,697** |
| 56 | 50 | **Power Services Transmission Acquisition and Ancillary Services** | | |
| 57 | 51 | **Transmission Acquisition and Ancillary Services** | | |
| 58 | 52 | TRANSMISSION & ANCILLARY SERVICES | | |
| 59 | 53 | Canadian Entitlement Agreement Transmission Expenses | $ 27,000 | $ 27,000 |
| 60 | 54 | PNCA & NTS Transmission and System Obligaton Expenses | $ 1,000 | $ 1,000 |
| 61 | 55 | 3RD PARTY GTA WHEELING | $ 50,690 | $ 51,340 |
| 62 | 56 | 3RD PARTY TRANS & ANCILLARY SVCS | | |
| 63 | 57 | GENERATION INTEGRATION | $ 6,800 | $ 6,800 |
| 64 | 58 | TELEMETERING/EQUIP REPLACEMT | $ 50 | $ 50 |
| 65 | 59 | **Power Services Trans Acquisition and Ancillary Serv Sub-Total** | **$ 85,540** | **$ 86,190** |
| 66 | 60 | | | |
| 67 | 61 | **Power Non-Generation Operations** | | |
| 68 | 62 | **System Operations** | | |
| 69 | 63 | SYSTEM OPERATIONS R&D | $ - | $ - |
| 70 | 64 | EFFICIENCIES PROGRAM (excludes TMS expenses) | $ - | $ - |
| 71 | 65 | INFORMATION TECHNOLOGY | $ 6,318 | $ 6,282 |
| 72 | 66 | GENERATION PROJECT COORDINATION | $ 7,290 | $ 7,542 |
| 73 | 67 | SLICE IMPLEMENTATION (omit - calculated separately) | | |
| 74 | 68 | **Sub-Total** | **$ 13,608** | **$ 13,824** |
| 75 | 69 | **Scheduling** | | |
| 76 | 70 | SCHEDULING R&D | | |
| 77 | 71 | OPERATIONS SCHEDULING | $ 9,317 | $ 9,564 |
| 78 | 72 | OPERATIONS PLANNING | $ 5,808 | $ 5,874 |
| 79 | 73 | **Sub-Total** | **$ 15,125** | **$ 15,438** |
| 80 | 74 | **Marketing and Business Support** | | |
| 81 | 75 | SALES & SUPPORT | $ 16,699 | $ 17,885 |
| 82 | 76 | Contractual exclusion | $ (5,360) | $ (5,360) |
| 83 | 77 | Implementation Expense Exclusions - Add back | | |
| 84 | 78 | PUBLIC COMMUNICATION & TRIBAL LIAISON | | |
| 85 | 79 | STRATEGY, FINANCE & RISK MGMT | $ 16,870 | $ 17,343 |
| 86 | 80 | EXECUTIVE AND ADMINISTRATIVE SERVICES | $ 2,546 | $ 2,727 |
| 87 | 81 | CONSERVATION SUPPORT (EE staff costs) | $ 11,356 | $ 12,003 |
| 88 | 82 | **Sub-Total** | **$ 42,111** | **$ 44,598** |
| 89 | 83 | **Power Non-Generation Operations Sub-Total** | **$ 70,844** | **$ 73,860** |

| | A | B | C | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|
| 1 | | **Table 2.13.1 (2 of 2)** | | | | | | |
| 2 | | **Slice Costing Table** | | | | | | |
| 3 | | | | **FY 2010 forecast** | | **FY 2011 forecast** | | |
| 4 | 84 | **Fish and Wildlife/USF&W/Planning Council/Environmental Req** | | | | | | |
| 5 | 85 | **BPA Fish and Wildlife (includes F&W Shared Services)** | | | | | | |
| 6 | 86 | FISH & WILDLIFE | | $ 215,000 | | $ 236,000 | | |
| 7 | 87 | **Sub-Total** | | **$ 215,000** | | **$ 236,000** | | |
| 8 | 88 | **USF&W Lower Snake Hatcheries** | | | | | | |
| 9 | 89 | USF&W LOWER SNAKE HATCHERIES | | $ 23,600 | | $ 24,480 | | |
| 10 | 90 | **Planning Council** | | | | | | |
| 11 | 91 | PLANNING COUNCIL | | $ 9,683 | | $ 9,934 | | |
| 12 | 92 | **Environmental Requirements** | | | | | | |
| 13 | 93 | ENVIRONMENTAL REQUIREMENTS | | $ 300 | | $ 300 | | |
| 14 | 94 | **Fish and Wildlife/USF&W/Planning Council Sub-Total** | | **$ 248,583** | | **$ 270,714** | | |
| 15 | 95 | **General and Administrative/Shared Services** | | | | | | |
| 16 | 96 | **Additional Post-Retirement Contribution** | | | | | | |
| 17 | 97 | ADDITIONAL POST-RETIREMENT CONTRIBUTION | | $ 15,447 | | $ 15,579 | | |
| 18 | 98 | **BPA Internal Support - G&A and Shared Srv. (excludes direct project support)** | | | | | | |
| 19 | 99 | AGENCY SERVICES G&A | | $ 49,961 | | $ 50,064 | | |
| 20 | 100 | **Sub-Total BPA Internal Support Services** | | **$ 49,961** | | **$ 50,064** | | |
| 21 | 101 | **Supply Chain - Shared Services** | | | | | | |
| 22 | 102 | **General and Administrative/Shared Services Sub-Total** | | **$ 65,408** | | **$ 65,643** | | |
| 23 | 103 | **Bad Debt Expense** | | $ - | | $ - | | |
| 24 | 104 | **Other Income, Expenses, Adjustments** | | **$ -** | | **$ -** | | |
| 25 | 105 | **Non-Federal Debt Service** | | | | | | |
| 26 | 106 | **Energy Northwest Debt Service** | | | | | | |
| 27 | 107 | COLUMBIA GENERATING STATION DEBT SVC | | $ 235,736 | | $ 226,169 | | |
| 28 | 108 | WNP-1 DEBT SVC | | $ 166,013 | | $ 167,549 | | |
| 29 | 109 | WNP-3 DEBT SVC | | $ 144,892 | | $ 169,093 | | |
| 30 | 110 | EN RETIRED DEBT | | | | | | |
| 31 | 111 | EN LIBOR INTEREST RATE SWAP | | | | | | |
| 32 | 112 | **Sub-Total** | | **$ 546,641** | | **$ 562,811** | | |
| 33 | 113 | **Non-EN Debt Service** | | | | | | |
| 34 | 114 | COWLITZ FALLS DEBT SVC | | $ 11,566 | | $ 11,563 | | |
| 35 | 115 | N. WASCO DEBT SVC | | $ 2,200 | | $ 2,196 | | |
| 36 | 116 | TROJAN DEBT SVC | | $ - | | $ - | | |
| 37 | 117 | CONSERVATION DEBT SVC | | $ 5,079 | | $ 4,924 | | |
| 38 | 118 | **Sub-Total** | | **$ 18,845** | | **$ 18,683** | | |
| 39 | 119 | **Non-Federal Debt Service Sub-Total** | | **$ 565,486** | | **$ 581,494** | | |
| 40 | 120 | **Depreciation (excludes TMS)** | | $ 120,111 | | $ 121,235 | | |
| 41 | 121 | **Amortization (excludes ConAug amortization)** | | $ 64,392 | | $ 72,363 | | |
| 42 | 122 | **Total Operating Expenses** | | **$ 2,204,403** | | **$ 2,336,196** | | |
| 43 | 123 | | | | | | | |
| 44 | 124 | **Other Expenses** | | | | | | |
| 45 | 125 | Net Interest Expense | | $ 167,119 | | $ 173,301 | | |
| 46 | 126 | LDD | | $ 26,419 | | $ 26,465 | | |
| 47 | 127 | Irrigation Rate Mitigation Costs | | $ 12,036 | | $ 12,036 | | |
| 48 | 128 | **Sub-Total** | | **$ 205,574** | | **$ 211,802** | | |
| 49 | 129 | **Total Expenses** | | **$ 2,409,977** | | **$ 2,547,998** | | |
| 50 | 130 | | | | | | | |
| 51 | 131 | **Revenue Credits** | | | | | | |
| 52 | 132 | Ancillary and Reserve Service Revs. Total | | $ 90,176 | | $ 102,730 | | |
| 53 | 133 | Downstream Benefits and Pumping Power | | $ 8,921 | | $ 8,921 | | |
| 54 | 134 | 4(h)(10)(c) | | $ 96,689 | | $ 101,969 | | |
| 55 | 135 | Colville and Spokane Settlements | | $ 4,600 | | $ 4,600 | | |
| 56 | 136 | FCCF | | | | | | |
| 57 | 137 | Energy Efficiency Revenues | | $ 20,500 | | $ 20,500 | | |
| 58 | 138 | Miscellaneous | | $ 3,420 | | $ 3,420 | | |
| 59 | 139 | Green Tag revenue associated with Klondike III | | $ - | | $ - | | |
| 60 | 140 | Ad Hoc revenue credit adjustment | | | | | | |
| 61 | 141 | **Total Revenue Credits** | | **$ 224,306** | | **$ 242,140** | | |
| 62 | 142 | **Augmentation Costs (not subject to True-Up)** | | | | | | |
| 63 | 143 | **Non-Slice Net Augmentation Costs** | | | | | | |
| 64 | 144 | Gross Augmentation cost (72.7 aMW, 274.7 aMW) | | $ 26,023 | | $ 108,365 | | |
| 65 | 145 | Minus revenues 70.7 aMW, 267.1 aMW @ PF rate | | $ (17,818) | | $ (67,316) | | |
| 66 | 146 | | | **$ 8,205** | | **$ 41,049** | | |
| 67 | 147 | **DSI Net Augmentation Costs** | | | | | | |
| 68 | 148 | Gross Augmentation cost (413 aMW, 413 aMW) | | $ 154,746 | | $ 164,668 | | |
| 69 | 149 | Minus revenues 402 aMW, 402 aMW @ IP rate | | $ (121,852) | | $ (121,852) | | |
| 70 | 150 | | | **$ 32,895** | | **$ 42,815** | | |
| 71 | 151 | | | | | | | |
| 72 | 152 | **Total Net Cost of Augmentation** | | **$ 41,100** | | **$ 83,864** | | |
| 73 | 153 | | | | | | | |
| 74 | 154 | | | | | | | |
| 75 | 155 | **Minimum Required Net Revenue calculation** | | | | | | |
| 76 | 156 | Principal Payment of Fed Debt for Power | | $ 202,673 | | $ 204,163 | | |
| 77 | 157 | Irrigation assistance | | $ - | | $ - | | |
| 78 | 158 | Depreciation | | $ 120,111 | | $ 121,235 | | |
| 79 | 159 | Amortization | | $ 77,728 | | $ 85,699 | | |
| 80 | 160 | Capitalization Adjustment | | $ (45,937) | | $ (45,937) | | |
| 81 | 161 | Bond Premium Amortization | | $ 185 | | $ 185 | | |
| 82 | 162 | Principal Payment of Fed Debt exceeds non cash expenses | | $ 50,586 | | $ 42,981 | | |
| 83 | 163 | Minimum Required Net Revenues | | **$ 50,586** | | **$ 42,981** | | |
| 84 | 164 | | | | | | | **2-Year Total Rev** |
| 85 | 165 | Annual Slice Revenue Requirement (Amounts for each FY) | | **$ 2,277,356** | | **$ 2,432,703** | | **$ 4,710,060** |
| 86 | 166 | | | | | | | |
| 87 | 167 | SLICE TRUE-UP ADJUSTMENT CALCULATION | | | | | | |
| 88 | 168 | | | | | | | |
| 89 | 169 | FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case | | | | | | |
| 90 | 170 | TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt) | | | | | | |
| 91 | 171 | AMOUNT BILLED (22.6278 percent) | | | | | | |
| 92 | 172 | Slice Implementation Expenses (not incl. in base rate) | | | | | | |
| 93 | 173 | TRUE UP ADJUSTMENT | | | | | | |
| 94 | 174 | | | | | | | |
| 95 | 175 | | | | | | | |
| 96 | 176 | **SLICE RATE CALCULATION ($)** | | | | | | |
| 97 | 177 | **Monthly Slice Revenue Requirement (2-Year total divided by 24 months)** | | | | | | **$ 196,252,498** |
| 98 | 178 | **One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)** | | | | | | **$ 1,962,525** |
| 99 | 179 | | | | | | | |
| 100 | 180 | **ANNUAL BASE SLICE REVENUES** | | | | | | **$ 532,891,473** |
| 101 | 181 | **Annual Slice Implementation Expenses** | | | | | | **$ 2,830,000** |
| 102 | 182 | **TOTAL ANNUAL SLICE REVENUES** | | | | | | **$ 535,721,473** |

## Table 2.13.2

### FINAL PROPOSAL WITH/WITHOUT 7B3 ALLOCATION TO SECONDARY

### Final Proposal Rate and Benefit Summary

| | 2010-11 | | 2010-11 7b2 Trigger |
|---|---|---|---|
| Unbifurcated PF | $ 36.32 | | 8.17 |
| PF Preference (average non-Slice) | $ 28.77 | 6.95% | |
| PF Exchange (w/ Transmission) | $ 48.68 | | 7b3 |
| IP | $ 34.60 | | 7.380 |
| NR | $ 68.67 | | |

| IOU Net Exchange Benefits | FY 2010 | FY 2011 | |
|---|---|---|---|
| Avista | $ 12,517 | $ 12,425 | |
| Idaho Power | $ - | $ - | |
| Northwestern Energy PNWR | $ 5,164 | $ 4,545 | |
| Pacificorp | $ 74,394 | $ 65,786 | |
| Portland General | $ 64,314 | $ 66,368 | |
| Puget Sound Energy | $ 95,959 | $ 108,102 | |
| | $ 252,349 | $ 257,227 | $ 254,788 |
| | | | Slice |
| Net Public Exchange | $ 12,101 | $ 10,016 | $ 535,723 |
| | | 2010-11 Net Augmentation Costs | $ 124,979 |

### Final Proposal with No 7b3 Allocation to FPS/Secondary Summary

| | 2010-11 | | 2010-11 7b2 Trigger |
|---|---|---|---|
| Unbifurcated PF | $ 34.53 | | 6.82 |
| PF Preference (average non-Slice) | $ 28.32 | 5.28% | |
| PF Exchange (w/ Transmission) | $ 49.20 | | 7b3 |
| IP | $ 36.61 | | 9.810 |
| NR | $ 71.05 | | |

| IOU Net Exchange Benefits | FY 2010 | FY 2011 | |
|---|---|---|---|
| Avista | $ 13,075 | $ 12,869 | |
| Idaho Power | $ - | $ - | |
| Northwestern Energy PNWR | $ 4,668 | $ 4,168 | |
| Pacificorp | $ 67,623 | $ 60,682 | |
| Portland General | $ 58,889 | $ 60,713 | |
| Puget Sound Energy | $ 86,900 | $ 97,256 | |
| | $ 231,155 | $ 235,687 | $ 233,421 |
| | | | Slice |
| Net Public Exchange | $ 12,828 | $ 10,971 | $ 529,628 |
| | | 2010-11 Net Augmentation Costs | $ 112,154 |

#### 7B3 Allocations and Revenues From Requirements Sales

| | Final Proposal | No 7b3 Allocation to FPS/Secondary |
|---|---|---|
| Total 7b3 protection amount | $ 1,003,410 | $ 837,608 |
| 7b3 allocted to PFx | $ 577,879 | $ 768,474 |
| 7b3 allocted to IP | $ 51,988 | $ 69,134 |
| 7b3 allocated to secondary | $ 373,543 | $ - |
| slice rate revenues | $ 1,071,446 | $ 1,059,255 |
| non-slice revenues | $ 2,965,078 | $ 2,936,609 |
| | $ 4,036,524 | $ 3,995,864 |

#### PROOF THAT REQUIREMENT SALES REVENUE MINUS NET REP BENEFITS IS THE SAME WITH/WITHOUT THE ALLOCATION OF 7B3 AMOUNTS TO SECONDARY

| | | | | delta |
|---|---|---|---|---|
| Total PF&IP Revenue minus net REP | $ 3,504,831 | Total PF&IP Revenue minus net REP | $ 3,505,223 | $ 392 |
| | | | | 0.01% |

#### PROOF THAT SLICE IS ALLOCATED THE PROPER COSTS
#### WHEN 7B3 PROTECTION AMOUNTS ARE ALLOCATED TO SECONDARY

| | | |
|---|---|---|
| 1 | Change in REP Net Benefits Due to 7b3 to Secondary | $ 41,052 |
| 2 | Slice percent | 0.226278 |
| 3 | Slice Share of Change in REP Net Benefit Costs | $ 9,289 |
| 4 | | |
| 5 | Net Augmentation Costs with 7b3 to Secondary | $ 124,979 |
| 6 | Net Augmentation Costs without 7b3 to Secondary | $ 112,154 |
| 7 | decrease in Net Augmentation Due to 7b3 to Secondary | $ 12,825 |
| 8 | Slice percent | 0.226278 |
| 9 | Slice Share of Change in Net Augmentation | $ 2,902 |
| 10 | | |
| 11 | **Expected Change in Slice Cost (ln 3 plus ln 9)** | **$ 12,191** |
| 12 | | |
| 13 | | |
| 14 | Observed Slice Revenue with 7b3 to Secondary | $ 1,071,446 |
| 15 | Observed Slice Revenue with no 7b3 to Secondary | $ 1,059,255 |
| 16 | **Observed Change in Slice Costs** | **$ 12,191** |
| 17 | | |

Allocating 7b3 protection amounts to secondary has multiple effects:

1. The secondary revenue credit to the unbifurcated PF rate is reduced, raising that rate.
2. The 7b3 amount allocated to the PF Exchange rate is reduced.
3. The effect of 1 and 2 above is to reduce the PF Exchange rate.
4. The reduced PF Exchange rate produces increased REP benefits.

5. The 7b3 amount allocated to the IP rate is reduced and the IP rate is lowered.
6. The lower IP rate has the effect of increasing the cost of net augmentation.

7. As can be seen in the box to the left, Slice costs are increase to cover the slice percentage of the increased REP benefits and the increase in the net cost of augmentation.

# Table 2.14.1

**RDS 60A**

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

| | B | C | D | E |
|---|---|---|---|---|
| 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 | 1,234,212 | 6.137 | 16.90% |
| 16 | Fish & Wildlife | 571,415 | 2.841 | 7.82% |
| 17 | Trojan | 4,500 | 0.022 | 0.06% |
| 18 | WNP #1 | 334,408 | 1.663 | 4.58% |
| 19 | WNP #2 | 1,044,598 | 5.194 | 14.30% |
| 20 | WNP #3 | 313,985 | 1.561 | 4.30% |
| 21 | System Augmentation | 453,803 | 2.257 | 6.21% |
| 22 | Balancing Power Purchases | 159,738 | 0.794 | 2.19% |
| 23 | Total Federal Base System | 4,116,660 | 20.470 | 56.35% |
| 24 | New Resources | | | |
| 25 | Gross Residential Exchange | 3,152,994 | 15.678 | 43.16% |
| 26 | Conservation | 309,366 | 1.538 | 4.24% |
| 28 | BPA Programs | 580,704 | 2.888 | 7.95% |
| 29 | TOTAL COSA ALLOCATIONS | 8,159,723 | 40.574 | 109.17% |
| 30 | | | | |
| 31 | | | | |
| 32 | Nonfirm Excess Revenue Credit | (1,098,015) | -5.460 | -15.03% |
| 33 | Low Density Discount Expense | 52,884 | 0.263 | 0.72% |
| 34 | Other Revenue Credits | (439,432) | -2.185 | -6.02% |
| 35 | Irrigation Rate Mitigation Expense | 24,072 | 0.120 | 0.33% |
| 36 | SP Revenue Surplus/Dfct Adj. | 429,780 | 2.137 | 5.88% |
| 37 | 7(c)(2) Delta Adjustment | 175,958 | 0.875 | 2.41% |
| 38 | 7(c)(2) Floor Rate Adjustment | | | |
| 39 | TOTAL RATE DESIGN ADJUSTMENTS | (854,754) | -4.250 | -11.70% |
| 40 | | | | |
| 41 | Total Generation | 7,304,970 | **36.32** | 100.00% |
| 56 | | | | |
| 57 | Billing Determinants With LDD Discount | 201,106 | | |
| 58 | | | | |

## Table 2.14.2

**RDS 60B**

**RATE DESIGN STUDY**
**Allocated Costs and Unit Costs**
**Priority Firm Power (PF) Bifurcated**
**($ Thousands)**
**Test Period October 2008 - September 2009**

| | | A<br>ALLOCATED<br>COSTS | B<br>UNIT<br>COSTS | C<br>PERCENT<br>CONTRIBUTION |
|---|---|---|---|---|
| **Rate Design Step PF Rate** | | ($ Thousands) | (Mills/KwH) | (Percent) |
| **PRIORITY FIRM PREFERENCE** | | | | |
| Revenue Reqmt @ PF Combined Rate | | 4,461,173 | 36.324 | 129.02% |
| 7(b)(2) Credit | | (1,003,410) | -8.170 | -29.02% |
| | Subtotal | 3,457,763 | 28.154 | 100.00% |
| Floor Rate Adjustment | | | | |
| | TOTAL | 3,457,763 | 28.154 | 100.00% |
| Billing Determinants: | | | | |
| Total PF Preference Forecasted Sales | | 122,816 | 28.154 | 100.00% |
| **Slice Separation Step** | | | | |
| Revenue Reqmt @ Rate Design Step PF Pref. | | 3,457,763 | | |
| Slice PF Product Revenues | | (1,065,783) | | |
| Slice Secondary Revenue Credit Adjustment | | 332,981 | | |
| Slice Separation 7c2 Adjustement | | (3,346) | | |
| Revenue Reqmt @ Non-Slice PF Pref. | | 2,721,615 | | |
| Non-Slice PF Preference Forecasted Sales | | 94,582 | **28.775** | |
| **PRIORITY FIRM EXCHANGE** | | | | |
| Revenue Reqmt @ PF Combined Rate | | 2,843,797 | 36.324 | 74.62% |
| 7(b)(2) Adjustment | | 577,879 | 7.381 | 15.16% |
| 7(b)(2) Industrial Adjustment | | 56,101 | 0.717 | 1.47% |
| | Subtotal | 3,477,776 | 44.422 | 91.25% |
| Floor Rate Adjustment | | | | |
| | Total Energy | 3,477,776 | 44.422 | 91.25% |
| Total Transmission | | 333,515 | 4.260 | 8.75% |
| | TOTAL | 3,811,292 | **48.682** | 100.00% |
| Billing Determinants: | | | | |
| Forecasted Exchange Loads | | 78,290 | 48.682 | 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 2008 - September 2009** | | | |
| 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 | 62,005 | 8.804 | 25.44% |
| 25 | | Gross Residential Exchange | 325,123 | 46.162 | 133.40% |
| 26 | | Conservation | 10,834 | 1.538 | 4.45% |
| 27 | | BPA Programs | 20,337 | 2.888 | 8.34% |
| 28 | | TOTAL COSA ALLOCATIONS | 418,299 | 59.392 | 171.63% |
| 29 | | | | | |
| 30 | | Nonfirm Excess Revenue Credit | | | |
| 31 | | | | | |
| 32 | | Other Revenue Credits | | | |
| 33 | | | | | |
| 34 | | SP Revenue Surplus/Dfct Adj. | 2,143 | 0.304 | 0.88% |
| 35 | | 7(c)(2) Delta Adjustment | (175,958) | -24.983 | -72.20% |
| 36 | | 7(c)(2) Floor Rate Adjustment | | | |
| 37 | | TOTAL RATE DESIGN ADJSTMTS | (173,815) | -24.679 | -71.32% |
| 38 | | Total Generation | 244,484 | 34.713 | 100.31% |
| 39 | | | | | |
| 50 | | | | | |
| 51 | | Total Allocated & Adjusted Costs | 244,484 | 34.713 | 100.31% |
| 52 | | | | | |
| 53 | | 7(b)(2) Adjustments | | | |
| 54 | | 7(b)(2) Amount | 51,988 | 7.381 | 21.33% |
| 55 | | 7(b)(2) Industrial Adj. | (56,101) | -7.965 | -23.02% |
| 56 | | | 240,372 | 34.129 | 98.63% |
| 57 | | | | | |
| 58 | | Slice Separation Step Adjustment | | | |
| 59 | | 7(c)(2) Slice Separation Amount | 3,346 | 0.475 | 1.37% |
| 60 | | Total With 7(b)(2) Adjustments | 243,717 | **34.604** | 100.00% |
| 61 | | | | | |
| 62 | | Billing Determinants: | | | |
| 63 | | Energy (GwH) | 7,043 | | |

## 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 2008 - September 2009**

| Row | | A<br>ALLOCATED<br>COSTS | B<br>UNIT<br>COSTS | C<br>PERCENT<br>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 | 0.0154 | 8.804 | 12.82% |
| 25 | Gross Residential Exchange | 0.0809 | 46.162 | 67.22% |
| 26 | Conservation | 0.0027 | 1.538 | 2.24% |
| 27 | BPA Programs | 0.0051 | 2.888 | 4.21% |
| 28 | TOTAL COSA ALLOCATIONS | 0.1041 | 59.392 | 86.49% |
| 29 | | | | |
| 30 | Nonfirm Excess Revenue Credit | | | |
| 31 | | | | |
| 34 | SP Revenue Surplus/Dfct Adj. | 0.0005 | 0.304 | 0.44% |
| 35 | 7(c)(2) Delta Adjustment | 0.0015 | 0.875 | 1.27% |
| 36 | 7(c)(2) Floor Rate Adjustment | | | |
| 37 | TOTAL RATE DESIGN ADJSTMTS | 0.0021 | 1.179 | 1.72% |
| 38 | Total Generation Energy | 0.1061 | 60.571 | 88.21% |
| 47 | | | | |
| 49 | Total Allocated & Adjusted Costs | 0.1061 | 60.571 | 88.21% |
| 50 | 7(b)(2) Adjustments | | | |
| 51 | 7(b)(2) Amount | 0.0129 | 7.381 | 10.75% |
| 52 | 7(b)(2) Industrial Adj. | 0.0013 | 0.717 | 1.04% |
| 53 | 7(b(2)Exchange Cost Adjustment | | | |
| 54 | Total With 7(b)(2) Adjustments | 0.1203 | **68.67** | 100.00% |
| 55 | | | | |
| 56 | Billing Determinant / Energy (GWh) | 0.0018 | | |

## Table 2.14.5

**RDS63**

| | 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 | 2,514,060 | 1,925,545 | | 4,439,605 | 56.63% | 43.37% | | 100.00% |
| Priority Firm - Exchange | 1,602,600 | 1,227,448 | | 2,830,048 | 56.63% | 43.37% | | 100.00% |
| Priority Firm Power - Total | 4,116,660 | 3,152,994 | | 7,269,653 | 56.63% | 43.37% | | 100.00% |
| Industrial Firm Power | | 325,123 | 62,005 | 387,128 | | 83.98% | 16.02% | 100.00% |
| New Resources Firm | | 0.081 | 0.015 | 0.096 | | 83.98% | 16.02% | 100.00% |
| Firm Power Products and Services | | 535,360 | 102,118 | 637,478 | | 83.98% | 16.02% | 100.00% |
| **TOTALS** | **4,116,660** | **4,013,477** | **164,123** | **8,294,260** | **49.63%** | **48.39%** | **1.98%** | **100.00%** |
| | | | | 233,908 | | | | |
| | | | Average Cost of Resources | 35.46 | | | | |

# CHAPTER 3: SLICE TRUE-UP ADJUSTMENT CHARGE FORECAST TABLES

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**Table 3.1**

Slice True-Up Adjustment Charge Forecast after $42M Shift in Generation Amortization Payments to the US Treasury

($000s)

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 1 | | | Audited Actual Data | FY 2010 forecast | | FY 2011 forecast | | |
| 2 | 1 | **Operating Expenses** | | | | | | |
| 3 | 2 | **Power System Generation Resources** | | | | | | |
| 4 | 3 | **Operating Generation** | | | | | | |
| 5 | 4 | COLUMBIA GENERATING STATION (WNP-2) | | $ 257,811 | | $ 324,882 | | |
| 6 | 5 | BUREAU OF RECLAMATION | | $ 87,318 | | $ 96,110 | | |
| 7 | 6 | CORPS OF ENGINEERS | | $ 191,060 | | $ 192,433 | | |
| 8 | 7 | LONG-TERM CONTRACT GENERATING PROJECTS | | $ 30,455 | | $ 30,767 | | |
| 9 | 8 | **Sub-Total** | | **$ 566,644** | | **$ 644,192** | | |
| 10 | 9 | **Operating Generation Settlement Payment** | | | | | | |
| 11 | 10 | COLVILLE GENERATION SETTLEMENT | | $ 21,328 | | $ 21,754 | | |
| 12 | 11 | **Sub-Total** | | **$ 21,328** | | **$ 21,754** | | |
| 13 | 12 | **Non-Operating Generation** | | | | | | |
| 14 | 13 | TROJAN DECOMMISSIONING | | $ 2,200 | | $ 2,300 | | |
| 15 | 14 | WNP-1&3 DECOMMISSIONING | | $ 418 | | $ 428 | | |
| 16 | 15 | **Sub-Total** | | **$ 2,618** | | **$ 2,728** | | |
| 17 | 16 | **Contracted Power Purchases** | | | | | | |
| 18 | 17 | HEDGING/MITIGATION (omit except for those assoc. with inventory solution) | | $ - | | $ - | | |
| 19 | 18 | PNCA HEADWATER BENEFITS | | $ 2,042 | | $ 2,620 | | |
| 20 | 19 | GROSS OTHER POWER PURCHASES (short term - omit) | | | | | | |
| 21 | 20 | **Sub-Total** | | **$ 2,042** | | **$ 2,620** | | |
| 22 | 21 | **Bookout Adjustment to Power Purchases (omit)** | | | | | | |
| 23 | 22 | **Augmentation Power Purchases (omit - calculated below)** | | | | | | |
| 24 | 23 | AUGMENTATION POWER PURCHASES (omit) | | | | | | |
| 25 | 24 | CONSERVATION AUGMENTATION (omit) | | | | | | |
| 26 | 25 | **Sub-Total** | | **$ -** | | **$ -** | | |
| 27 | 26 | **Exchanges and Settlements** | | | | | | |
| 28 | 27 | PUBLIC RESIDENTIAL EXCHANGE | | $ 12,101 | | $ 10,016 | | |
| 29 | 28 | IOU RESIDENTIAL EXCHANGE | | $ 254,770 | | $ 258,667 | | |
| 30 | 29 | OTHER SETTLEMENTS | | $ - | | $ - | | |
| 31 | 30 | **Sub-Total** | | **$ 266,871** | | **$ 268,683** | | |
| 32 | 31 | **Renewable Generation** | | | | | | |
| 33 | 32 | RENEWABLES R&D | | $ 6,174 | | $ 6,133 | | |
| 34 | 33 | RENEWABLES CONSERVATION RATE CREDIT | | $ 4,000 | | $ 2,500 | | |
| 35 | 34 | RENEWABLES (excludes expenses from reinvested revenues) | | $ 30,374 | | $ 30,965 | | |
| 36 | 35 | **Sub-Total** | | **$ 40,548** | | **$ 39,598** | | |
| 37 | 36 | **Generation Conservation** | | | | | | |
| 38 | 37 | GENERATION CONSERVATION R&D | | | | | | |
| 39 | 38 | DSM TECHNOLOGIES | | $ - | | $ - | | |
| 40 | 39 | CONSERVATION ACQUISITION | | $ 14,000 | | $ 14,000 | | |
| 41 | 40 | LOW INCOME WEATHERIZATION & TRIBAL | | $ 5,000 | | $ 5,000 | | |
| 42 | 41 | ENERGY EFFICIENCY DEVELOPMENT | | $ 20,500 | | $ 20,500 | | |
| 43 | 42 | LEGACY | | $ 1,988 | | $ 1,622 | | |
| 44 | 43 | MARKET TRANSFORMATION | | $ 14,500 | | $ 14,500 | | |
| 45 | 44 | **Sub-Total** | | **$ 55,988** | | **$ 55,622** | | |
| 46 | 45 | **Conservation and Renewable Discount (C&RD)** | | | | | | |
| 47 | 46 | CONSERVATION RATE CREDIT | | $ 28,000 | | $ 29,500 | | |
| 48 | 47 | CONSERVATION AND RENEWABLE DISCOUNT | | | | | | |
| 49 | 48 | **Sub-Total** | | **$ 28,000** | | **$ 29,500** | | |
| 50 | 49 | **Power System Generation Sub-Total** | | **$ 984,039** | | **$ 1,064,697** | | |
| 51 | 50 | **Power Services Transmission Acquisition and Ancillary Services** | | | | | | |
| 52 | 51 | **Transmission Acquisition and Ancillary Services** | | | | | | |
| 53 | 52 | TRANSMISSION & ANCILLARY SERVICES | | | | | | |
| 54 | 53 | Canadian Entitlement Agreement Transmission Expenses | | $ 27,000 | | $ 27,000 | | |
| 55 | 54 | PNCA & NTS Transmission and System Obligaton Expenses | | $ 1,000 | | $ 1,000 | | |
| 56 | 55 | 3RD PARTY GTA WHEELING | | $ 50,690 | | $ 51,340 | | |
| 57 | 56 | 3RD PARTY TRANS & ANCILLARY SVCS | | | | | | |
| 58 | 57 | GENERATION INTEGRATION | | $ 6,800 | | $ 6,800 | | |
| 59 | 58 | TELEMETERING/EQUIP REPLACEMT | | $ 50 | | $ 50 | | |
| 60 | 59 | **Power Services Trans Acquisition and Ancillary Serv Sub-Total** | | **$ 85,540** | | **$ 86,190** | | |
| 61 | 60 | | | | | | | |
| 62 | 61 | **Power Non-Generation Operations** | | | | | | |
| 63 | 62 | **System Operations** | | | | | | |
| 64 | 63 | SYSTEM OPERATIONS R&D | | $ - | | $ - | | |
| 65 | 64 | EFFICIENCIES PROGRAM (excludes TMS expenses) | | $ - | | $ - | | |
| 66 | 65 | INFORMATION TECHNOLOGY | | $ 6,318 | | $ 6,282 | | |
| 67 | 66 | GENERATION PROJECT COORDINATION | | $ 7,290 | | $ 7,542 | | |
| 68 | 67 | SLICE IMPLEMENTATION (omit - calculated separately) | | | | | | |
| 69 | 68 | **Sub-Total** | | **$ 13,608** | | **$ 13,824** | | |
| 70 | 69 | **Scheduling** | | | | | | |
| 71 | 70 | SCHEDULING R&D | | | | | | |
| 72 | 71 | OPERATIONS SCHEDULING | | $ 9,317 | | $ 9,564 | | |
| 73 | 72 | OPERATIONS PLANNING | | $ 5,808 | | $ 5,874 | | |
| 74 | 73 | **Sub-Total** | | **$ 15,125** | | **$ 15,438** | | |
| 75 | 74 | **Marketing and Business Support** | | | | | | |
| 76 | 75 | SALES & SUPPORT | | $ 16,699 | | $ 17,885 | | |
| 77 | 76 | Contractual exclusion | | $ (5,360) | | $ (5,360) | | |
| 78 | 77 | Implementation Expense Exclusions - Add back | | | | | | |
| 79 | 78 | PUBLIC COMMUNICATION & TRIBAL LIAISON | | | | | | |
| 80 | 79 | STRATEGY, FINANCE & RISK MGMT | | $ 16,870 | | $ 17,343 | | |
| 81 | 80 | EXECUTIVE AND ADMINISTRATIVE SERVICES | | $ 2,546 | | $ 2,727 | | |
| 82 | 81 | CONSERVATION SUPPORT (EE staff costs) | | $ 11,356 | | $ 12,003 | | |
| 83 | 82 | **Sub-Total** | | **$ 42,111** | | **$ 44,598** | | |
| 84 | 83 | **Power Non-Generation Operations Sub-Total** | | **$ 70,844** | | **$ 73,860** | | |
| 85 | 84 | **Fish and Wildlife/USF&W/Planning Council/Environmental Req** | | | | | | |
| 86 | 85 | **BPA Fish and Wildlife (includes F&W Shared Services)** | | | | | | |
| 87 | 86 | FISH & WILDLIFE | | $ 215,000 | | $ 236,000 | | |
| 88 | 87 | **Sub-Total** | | **$ 215,000** | | **$ 236,000** | | |

**Table 3.1**

Slice True-Up Adjustment Charge Forecast after $42M Shift in Generation Amortization Payments to the US Treasury

($000s)

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 1 | | | Audited Actual Data | FY 2010 forecast | | FY 2011 forecast | | |
| 89 | 88 | **USF&W Lower Snake Hatcheries** | | | | | | |
| 90 | 89 | USF&W LOWER SNAKE HATCHERIES | | $ 23,600 | | $ 24,480 | | |
| 91 | 90 | **Planning Council** | | | | | | |
| 92 | 91 | PLANNING COUNCIL | | $ 9,683 | | $ 9,934 | | |
| 93 | 92 | **Environmental Requirements** | | | | | | |
| 94 | 93 | ENVIRONMENTAL REQUIREMENTS | | $ 300 | | $ 300 | | |
| 95 | 94 | **Fish and Wildlife/USF&W/Planning Council Sub-Total** | | **$ 248,583** | | **$ 270,714** | | |
| 96 | 95 | **General and Administrative/Shared Services** | | | | | | |
| 97 | 96 | **Additional Post-Retirement Contribution** | | | | | | |
| 98 | 97 | ADDITIONAL POST-RETIREMENT CONTRIBUTION | | $ 15,447 | | $ 15,579 | | |
| 99 | 98 | **BPA Internal Support - G&A and Shared Srv. (excludes direct project support)** | | | | | | |
| 100 | 99 | AGENCY SERVICES G&A | | $ 49,961 | | $ 50,064 | | |
| 101 | 100 | **Sub-Total BPA Internal Support Services** | | **$ 49,961** | | **$ 50,064** | | |
| 102 | 101 | **Supply Chain - Shared Services** | | | | | | |
| 103 | 102 | **General and Administrative/Shared Services Sub-Total** | | **$ 65,408** | | **$ 65,643** | | |
| 104 | 103 | **Bad Debt Expense** | | $ - | | $ - | | |
| 105 | 104 | **Other Income, Expenses, Adjustments** | | **$ -** | | **$ -** | | |
| 106 | 105 | **Non-Federal Debt Service** | | | | | | |
| 107 | 106 | **Energy Northwest Debt Service** | | | | | | |
| 108 | 107 | COLUMBIA GENERATING STATION DEBT SVC | | $ 235,736 | | $ 226,169 | | |
| 109 | 108 | WNP-1 DEBT SVC | | $ 166,013 | | $ 167,549 | | |
| 110 | 109 | WNP-3 DEBT SVC | | $ 144,892 | | $ 169,093 | | |
| 111 | 110 | EN RETIRED DEBT | | | | | | |
| 112 | 111 | EN LIBOR INTEREST RATE SWAP | | | | | | |
| 113 | 112 | **Sub-Total** | | **$ 546,641** | | **$ 562,811** | | |
| 114 | 113 | **Non-EN Debt Service** | | | | | | |
| 115 | 114 | COWLITZ FALLS DEBT SVC | | $ 11,566 | | $ 11,563 | | |
| 116 | 115 | N. WASCO DEBT SVC | | $ 2,200 | | $ 2,196 | | |
| 117 | 116 | TROJAN DEBT SVC | | $ - | | $ - | | |
| 118 | 117 | CONSERVATION DEBT SVC | | $ 5,079 | | $ 4,924 | | |
| 119 | 118 | **Sub-Total** | | **$ 18,845** | | **$ 18,683** | | |
| 120 | 119 | **Non-Federal Debt Service Sub-Total** | | **$ 565,486** | | **$ 581,494** | | |
| 121 | 120 | **Depreciation (excludes TMS)** | | $ 120,111 | | $ 121,235 | | |
| 122 | 121 | **Amortization (excludes ConAug amortization)** | | $ 64,392 | | $ 72,363 | | |
| 123 | 122 | **Total Operating Expenses** | | **$ 2,204,403** | | **$ 2,336,196** | | |
| 124 | 123 | | | | | | | |
| 125 | 124 | **Other Expenses** | | | | | | |
| 126 | 125 | Net Interest Expense | | $ 167,119 | | $ 173,301 | | |
| 127 | 126 | LDD | | $ 26,419 | | $ 26,465 | | |
| 128 | 127 | Irrigation Rate Mitigation Costs | | $ 12,036 | | $ 12,036 | | |
| 129 | 128 | **Sub-Total** | | **$ 205,574** | | **$ 211,802** | | |
| 130 | 129 | **Total Expenses** | | **$ 2,409,977** | | **$ 2,547,998** | | |
| 131 | 130 | | | | | | | |
| 132 | 131 | **Revenue Credits** | | | | | | |
| 133 | 132 | Ancillary and Reserve Service Revs. Total | | $ 90,176 | | $ 102,730 | | |
| 134 | 133 | Downstream Benefits and Pumping Power | | $ 8,921 | | $ 8,921 | | |
| 135 | 134 | 4(h)(10)(c) | | $ 96,689 | | $ 101,969 | | |
| 136 | 135 | Colville and Spokane Settlements | | $ 4,600 | | $ 4,600 | | |
| 137 | 136 | FCCF | | | | | | |
| 138 | 137 | Energy Efficiency Revenues | | $ 20,500 | | $ 20,500 | | |
| 139 | 138 | Miscellaneous | | $ 3,420 | | $ 3,420 | | |
| 140 | 139 | Green Tag revenue associated with Klondike III | | $ - | | $ - | | |
| 141 | 140 | Ad Hoc revenue credit adjustment | | | | | | |
| 142 | 141 | **Total Revenue Credits** | | **$ 224,306** | | **$ 242,140** | | |
| 143 | 142 | **Augmentation Costs (not subject to True-Up)** | | | | | | |
| 144 | 143 | **Non-DSI Net Augmentation Costs** | | | | | | |
| 145 | 144 | Gross Augmentation cost (72.7 aMW, 274.7 aMW) | | $ 26,019 | | $ 108,375 | | |
| 146 | 145 | Minus revenues 70.7 aMW, 267.1 aMW @ PF rate | | $ (17,815) | | $ (67,325) | | |
| 147 | 146 | | | **$ 8,204** | | **$ 41,050** | | |
| 148 | 147 | **DSI Net Augmentation Costs** | | | | | | |
| 149 | 148 | Gross Augmentation cost (413 aMW, 413 aMW) | | $ 154,746 | | $ 164,668 | | |
| 150 | 149 | Minus revenues 402 aMW, 402 aMW @ IP rate | | $ (121,852) | | $ (121,852) | | |
| 151 | 150 | | | **$ 32,895** | | **$ 42,815** | | |
| 152 | 151 | | | | | | | |
| 153 | 152 | **Total Net Cost of Augmentation** | | **$ 41,099** | | **$ 83,865** | | |
| 154 | 153 | | | | | | | |
| 155 | 154 | | | | | | | |
| 156 | 155 | **Minimum Required Net Revenue calculation** | | | | | | |
| 157 | 156 | Principal Payment of Fed Debt for Power | | $ 202,673 | | $ 204,163 | | |
| 158 | 156a | Shift in principal payment | | $ 42,000 | | $ (42,000) | | |
| 159 | 157 | Irrigation assistance | | $ - | | $ - | | |
| 160 | 158 | Depreciation | | $ 120,111 | | $ 121,235 | | |
| 161 | 159 | Amortization | | $ 77,728 | | $ 85,699 | | |
| 162 | 160 | Capitalization Adjustment | | $ (45,937) | | $ (45,937) | | |
| 163 | 161 | Bond Premium Amortization | | $ 185 | | $ 185 | | |
| 164 | 162 | Principal Payment of Fed Debt exceeds non cash expenses | | $ 92,586 | | $ 981 | | |
| 165 | 163 | Minimum Required Net Revenues | | **$ 92,586** | | **$ 981** | | |
| 166 | 164 | | | | | | | **2-Year Total Rev** |
| 167 | 165 | Annual Slice Revenue Requirement (Amounts for each FY) | | **$ 2,319,356** | | **$ 2,390,704** | | **$ 4,710,060** |
| 168 | 166 | | | | | | | |
| 169 | 167 | SLICE TRUE-UP ADJUSTMENT CALCULATION | | | | | | |
| 170 | 168 | | | | | | | |
| 171 | 169 | FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case | | **$ 2,355,030** | | | | |
| 172 | 170 | TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt) | | $ (35,674) | | $ 35,674 | | |
| 173 | 171 | AMOUNT BILLED (22.6278 percent) | | $ (8,072) | | $ 8,072 | | |
| 174 | 172 | Slice Implementation Expenses (not incl. in base rate) | | $ 2,790 | | $ 2,870 | | |
| 175 | 173 | TRUE UP ADJUSTMENT | | **$ (5,282)** | **FY 2010** | **$ 10,942** | **FY 2011** | |
| 176 | 174 | | | | **True-Up** | | **True-Up** | |
| 177 | 175 | **SLICE RATE CALCULATION ($)** | | | | | | |
| 178 | 176 | **Monthly Slice Revenue Requirement (2-Year total divided by 24 months)** | | | | | | **$ 196,252,520** |
| 179 | 177 | **One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)** | | | | | | **$ 1,962,525** |
| 180 | 178 | | | | | | | |
| 181 | 179 | **ANNUAL BASE SLICE REVENUES** | | | | | | **$ 532,891,534** |
| 182 | 180 | **Annual Slice Implementation Expenses** | | | | | | **$ 2,830,000** |
| 183 | 181 | **TOTAL ANNUAL SLICE REVENUES** | | | | | | **$ 535,721,534** |

# CHAPTER 4:  REVENUE FORECAST

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## Table 4.5: 4h10C Credits

**4h10C Credits ($ Million)**

| Fiscal Year | Purch. Cost | BPA Exp. | BPA Cap. | Total | Credit @ 22.3% |
|---|---|---|---|---|---|
| **FY 2010** | 146.8 | 216.8 | 70.0 | 433.6 | **96.7** |
| **FY 2011** | 159.5 | 237.8 | 60.0 | 457.3 | **102.0** |

# Table 4.6.1 Summary of Revenues at Current Rates

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | FY 2009 | | FY 2010 | | FY 2011 | |
| 3 | | ($000) | aMW | ($000) | aMW | ($000) | aMW |
| 4 | **Revenues** | | | | | | |
| 5 | **PF Preference** | $1,228,242 | 5,299 | $1,212,059 | 5,211 | $1,229,472 | 5,284 |
| 6 | **Lookback Adjustment** | ($70,769) | 0 | $0 | 0 | $0 | 0 |
| 7 | **PF Slice** | $502,645 | 1,680 | $508,173 | 2,082 | $523,821 | 2,067 |
| 8 | **Pre-sub/Hungry Horse** | $37,626 | 210 | $45,156 | 199 | $45,695 | 201 |
| 9 | **Irrigation Mitigation** | $20,212 | 196 | $22,022 | 191 | $21,953 | 190 |
| 10 | **Industrial Power** | $0 | 0 | $122,619 | 402 | $122,619 | 402 |
| 11 | **Long-Term Obligations** | $91,498 | 624 | $85,694 | 655 | $78,483 | 609 |
| 12 | **Generation Inputs/Reserve Services** | $80,897 | 24 | $101,590 | 14 | $101,590 | 14 |
| 13 | **Slice True-Up** | $5,370 | 0 | ($5,282) | 0 | $10,942 | 0 |
| 14 | **Network Wind Integration & Shaping** | $1,989 | 0 | $1,953 | 0 | $1,953 | 0 |
| 15 | **4h10C credits** | $78,578 | 0 | $96,689 | 0 | $101,969 | 0 |
| 16 | **Colville credits** | $4,600 | 0 | $4,600 | 0 | $4,600 | 0 |
| 17 | **Downstream Benefits/Storage** | $9,646 | 175 | $8,921 | 175 | $8,921 | 175 |
| 18 | **Energy Efficiency** | $14,500 | 0 | $20,500 | 0 | $20,500 | 0 |
| 19 | **Green Tags/Green Premiums** | $3,644 | 0 | $5,040 | 0 | $5,040 | 0 |
| 20 | **Misc Generation** | $3,927 | 0 | $3,420 | 0 | $3,420 | 0 |
| 21 | **Secondary Sales** | $327,742 | 1,164 | $544,632 | 1,694 | $593,944 | 1,751 |
| 22 | **Bookouts** | ($24,059) | -59 | $0 | 0 | $0 | 0 |
| 23 | **Ad hoc Gen Input adjustment** | | | | | | |
| 24 | **Total Revenue** | $2,316,288 | 9,312 | $2,777,787 | 10,623 | $2,874,922 | 10,693 |
| 25 | **Purchases** | | | | | | |
| 26 | **Augmentation Purchases** | $3,134 | 13 | $180,622 | 486 | $272,955 | 688 |
| 27 | **Secondary Purchases** | $211,930 | 553 | $84,566 | 195 | $70,692 | 149 |

# TABLE 4.6.1 REVENUE AT CURRENT RATES

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 17, 2009 @ 12:19 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | | FY2009 | | | | | | | | | | | | |
| 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 | | **West Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | $2,670 | $2,477 | $4,026 | $2,904 | $3,151 | $2,697 | $2,262 | $1,458 | $1,285 | $1,611 | $1,830 | $1,869 | $28,241 | | |
| 10 | | LLH Energy Flat | 275,595 | 328,586 | 414,396 | 401,655 | 336,365 | 326,384 | 301,624 | 289,916 | 252,472 | 266,250 | 254,797 | 263,424 | 3,711,464 | 424 | 3711 |
| 11 | | HLH Energy Flat | 461,962 | 452,386 | 622,642 | 597,386 | 521,181 | 525,558 | 477,297 | 430,813 | 420,450 | 411,867 | 430,484 | 409,319 | 5,761,345 | 658 | 5761 |
| 12 | | 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 | | | |
| 13 | | 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 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $5,343 | $7,465 | $9,883 | $8,017 | $6,781 | $6,257 | $5,318 | $4,108 | $2,487 | $4,454 | $5,058 | $5,840 | $71,012 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $12,694 | $14,092 | $20,242 | $16,488 | $14,692 | $13,743 | $11,713 | $8,832 | $7,799 | $9,411 | $11,520 | $11,305 | $152,532 | | |
| 16 | | Demand | 1,398 | 1,214 | 1,881 | 1,596 | 1,703 | 1,568 | 1,396 | 1,088 | 1,045 | 1,074 | 1,040 | 1,027 | 16,030 | | |
| 17 | | 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 | | | |
| 18 | | Demand Revenue = 17*18 | $2,563 | $2,477 | $4,026 | $2,904 | $3,151 | $2,697 | $2,262 | $1,458 | $1,285 | $1,611 | $1,830 | $1,869 | $28,134 | | |
| 19 | | Load Variance | 750,216 | 793,646 | 1,051,953 | 1,013,764 | 869,157 | 909,632 | 836,154 | 782,813 | 732,274 | 737,461 | 743,680 | 725,315 | 9,946,064 | 1135 | 9946 |
| 20 | | 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 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $315 | $365 | $484 | $466 | $400 | $418 | $385 | $360 | $337 | $339 | $342 | $334 | $4,545 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -1.66% | -1.84% | -1.95% | -1.95% | -1.94% | -2.38% | -2.38% | -2.44% | -2.40% | -2.28% | -2.26% | -2.26% | | | |
| 23 | | Low Density Discount | -$348 | -$449 | -$675 | -$543 | -$486 | -$550 | -$468 | -$360 | -$286 | -$361 | -$425 | -$438 | -$5,388 | | |
| 24 | -1,008,619 | 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 | | |
| 25 | | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | | | |
| 26 | | PF Other revenues | $4 | $0 | $0 | $0 | $0 | | | | | | | | $4 | | |
| 27 | | | $6,680 | $7,889 | $9,843 | $7,950 | $6,833 | $6,270 | $5,250 | $5,048 | $2,636 | $4,855 | $5,766 | $6,458 | $75,479 | | |
| 28 | | **PF Partial Service** | $14,538 | $13,817 | $18,750 | $15,450 | $13,924 | $15,162 | $13,621 | $11,657 | $9,097 | $11,913 | $14,511 | $14,291 | $166,728 | | |
| 29 | | LLH Energy Flat | 312,148 | 347,212 | 412,690 | 398,298 | 338,926 | 327,080 | 297,780 | 356,279 | 267,650 | 290,224 | 290,497 | 291,308 | 3,930,093 | 449 | 3,930 |
| 30 | | HLH Energy Flat | 497,690 | 443,562 | 576,742 | 559,797 | 493,919 | 579,795 | 555,036 | 568,611 | 490,382 | 521,350 | 542,248 | 517,406 | 6,346,539 | 724 | 6,347 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $6,681 | $7,889 | $9,843 | $7,950 | $6,833 | $6,270 | $5,250 | $5,048 | $2,636 | $4,855 | $5,766 | $6,458 | $75,480 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $14,535 | $13,817 | $18,750 | $15,450 | $13,924 | $15,162 | $13,621 | $11,657 | $9,097 | $11,913 | $14,511 | $14,291 | $166,726 | | |
| 33 | | GSP Demand | 1,454 | 1,321 | 1,951 | 1,672 | 1,676 | 1,468 | 1,425 | 1,359 | 1,168 | 1,252 | 1,262 | 1,265 | 17,273 | | |
| 34 | | Demand Revenue (34*18) | $2,777 | $2,695 | $4,175 | $3,043 | $3,100 | $2,525 | $2,308 | $1,822 | $1,437 | $1,878 | $2,221 | $2,303 | $30,283 | | |
| 35 | | Load Variance | 1,038,945 | 1,019,974 | 1,238,664 | 1,211,281 | 1,063,890 | 1,144,954 | 1,087,995 | 1,052,352 | 1,007,251 | 1,042,228 | 1,053,565 | 1,021,789 | 12,982,888 | 1482 | 12983 |
| 36 | | Load Variance Revenue (36*21)/1000 | $478 | $469 | $570 | $557 | $489 | $527 | $500 | $484 | $463 | $479 | $485 | $470 | $5,972 | | |
| 37 | -1,133,980 | 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 | | |
| 38 | | PF Other Energy | 0 | 0 | 0 | 0 | 1 | | | | | | | | | | |
| 39 | | PF Other revenues | $0 | $23 | $0 | $0 | $0 | | | | | | | | $23 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | $16,430 | $20,167 | $25,574 | $21,827 | $20,124 | $18,720 | $13,534 | $8,416 | $7,202 | $9,998 | $12,887 | $15,465 | $190,343 | | |
| 42 | | LLH Energy Flat | 392,808 | 521,676 | 578,264 | 588,104 | 510,624 | 562,702 | 403,016 | 363,494 | 291,791 | 357,555 | 390,748 | 447,947 | 5,408,729 | 617 | 5,409 |
| 43 | | HLH Energy Flat | 562,464 | 647,424 | 786,656 | 790,816 | 713,856 | 715,854 | 551,495 | 410,513 | 388,255 | 437,536 | 481,595 | 559,934 | 7,046,398 | 804 | 7,046 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $8,406 | $11,852 | $13,792 | $11,739 | $10,294 | $10,787 | $7,105 | $5,151 | $2,874 | $5,982 | $7,756 | $9,931 | $105,669 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $16,430 | $20,167 | $25,574 | $21,827 | $20,124 | $18,720 | $13,534 | $8,416 | $7,202 | $9,998 | $12,887 | $15,465 | $190,343 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,408 | 1,812 | 2,006 | 2,059 | 1,992 | 1,721 | 1,326 | 1,137 | 1,088 | 1,225 | 1,308 | 1,400 | 18,482 | | |
| 49 | | Demand Revenue (49*24) | $2,689 | $3,696 | $4,293 | $3,747 | $3,685 | $2,960 | $2,148 | $1,523 | $1,338 | $1,838 | $2,303 | $2,548 | $32,769 | | |
| 50 | -1,309,822 | 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 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.89% | -0.79% | -0.80% | -0.81% | -0.79% | -0.75% | -1.00% | -0.94% | -0.87% | -0.78% | -0.71% | -0.95% | | | |
| 53 | | Low-Density Discount | -$246 | -$282 | -$351 | -$304 | -$271 | -$244 | -$228 | -$143 | -$99 | -$140 | -$162 | -$266 | -$2,735 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | $0 | | |
| 56 | | | | | | | | $0 | $0 | $1,334 | $1,603 | $2,428 | $2,494 | | $7,859 | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,975 | 39,179 | 0 | 152,052 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,493 | 65,398 | 73,313 | 64,136 | 0 | 248,340 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $710 | $721 | $1,383 | $1,568 | $0 | $4,382 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | 5,124 | 5,972 | 3,984 | 5,629 | 5,721 | 5,559 | 5,168 | 5,848 | 5,168 | 5,576 | 5,576 | 5,440 | 64,765 | 7 | 65 |
| 62 | | **Pt Townsend HLH** | 6,871 | 6,774 | 5,551 | 7,230 | 7,429 | 7,072 | 7,072 | 6,800 | 7,072 | 7,072 | 7,072 | 6,800 | 82,815 | 9 | 83 |
| 63 | | **Pt Townsend Demand** | 18 | 19 | 19 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 210 | | |
| 64 | | **Pt Townsend Revenues** | $359 | $401 | $328 | $357 | $371 | $328 | $299 | $252 | $210 | $288 | $337 | $346 | $3,876 | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF SLICE | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.51% | 1331 | |
| 68 | | 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 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $34,660 | $34,660 | $34,660 | $34,660 | $34,660 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $415,936 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | 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 | | |
| 72 | | LDD Percentage | -1.08% | -1.08% | -1.08% | -1.08% | -1.08% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | | | |
| 73 | | Low-Density Discount | -373 | -373 | -373 | -373 | -373 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$4,588 | | |
| 74 | | Slice Other | $0 | $0 | -$1,033 | $52 | $0 | | | | | | | | -$981 | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,248 | 1,348 | 1,312 | 1,312 | 1,152 | 6,867 | 6,384 | 7,224 | 6,384 | 6,888 | 6,888 | 6,720 | 53,727 | 6 | 54 |
| 77 | | LLH Energy Revenue | $27 | $27 | $26 | $26 | $23 | $27 | $25 | $29 | $25 | $27 | $27 | $27 | $315 | | |
| 78 | | HLH Energy Full Service | 1,728 | 1,536 | 1,664 | 1,664 | 1,536 | 8,736 | 8,736 | 8,400 | 8,736 | 8,736 | 8,736 | 8,400 | 68,608 | 8 | 69 |
| 79 | | HLH Energy Revenue | $34 | $30 | $33 | $33 | $30 | $35 | $35 | $33 | $35 | $35 | $35 | $33 | $400 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 167 | | |
| 81 | | Demand Revenue | -$4 | -$4 | -$4 | -$4 | -$4 | | | | | | | | -$20 | | |
| 82 | | Load Variance | 0 | 0 | 0 | 0 | 0 | 15,603 | 15,120 | 15,624 | 15,120 | 15,624 | 15,624 | 15,120 | 107,835 | 12 | 108 |
| 83 | | Load Variance Revenue | $0 | $0 | $0 | $0 | $0 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $50 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | $10 | $10 | $14 | $13 | $10 | | | | | | | | $57 | | |
| 88 | | **Total** | $102,491 | $114,484 | $140,744 | $121,509 | $112,891 | $109,398 | $93,542 | $79,115 | $67,298 | $83,727 | $95,796 | $100,253 | $1,263,672 | | |

# TABLE 4.6.1 REVENUE AT CURRENT RATES

| | A | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 17, 2009 @ 12:19 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | | **FY2010** | | | | | | | | | | | | |
| 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 | | **West Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | $2,783 | $3,211 | $3,632 | $3,225 | $3,175 | $2,664 | $2,237 | $1,430 | $1,280 | $1,619 | $1,806 | $1,855 | $28,916 | | |
| 10 | | LLH Energy Flat | 275,385 | 349,641 | 387,390 | 385,617 | 328,467 | 312,183 | 291,681 | 277,240 | 243,958 | 270,676 | 249,430 | 259,424 | 3,631,092 | 415 | 3631 |
| 11 | | HLH Energy Flat | 458,093 | 523,708 | 582,651 | 581,666 | 525,031 | 508,570 | 464,840 | 417,011 | 407,021 | 389,772 | 420,595 | 403,621 | 5,682,579 | 649 | 5683 |
| 12 | | 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 | | | |
| 13 | | 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 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $5,893 | $7,944 | $9,239 | $7,697 | $6,622 | $5,985 | $5,142 | $3,928 | $2,403 | $4,528 | $4,951 | $5,751 | $70,085 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $13,381 | $16,314 | $18,942 | $16,054 | $14,801 | $13,299 | $11,407 | $8,549 | $7,550 | $8,906 | $11,255 | $11,148 | $151,606 | | |
| 16 | | Demand | 1,457 | 1,574 | 1,697 | 1,772 | 1,716 | 1,549 | 1,381 | 1,067 | 1,041 | 1,079 | 1,026 | 1,019 | 16,378 | | |
| 17 | | 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 | | | |
| 18 | | Demand Revenue = 17*18 | $2,783 | $3,211 | $3,632 | $3,225 | $3,175 | $2,664 | $2,237 | $1,430 | $1,280 | $1,619 | $1,806 | $1,855 | $28,916 | | |
| 19 | | Load Variance | 754,019 | 895,929 | 995,586 | 991,790 | 875,886 | 843,421 | 781,180 | 721,793 | 677,495 | 685,878 | 694,615 | 682,762 | 9,600,354 | 1096 | 9600 |
| 20 | | 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 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $347 | $412 | $458 | $456 | $403 | $388 | $359 | $332 | $312 | $316 | $320 | $314 | $4,416 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -2.02% | -2.09% | -2.13% | -2.13% | -2.13% | -2.08% | -2.10% | -2.08% | -2.06% | -1.99% | -1.97% | -1.98% | | | |
| 23 | | Low Density Discount | -$452 | -$582 | -$688 | -$583 | -$532 | -$464 | -$401 | -$296 | -$238 | -$306 | -$362 | -$378 | -$5,283 | | |
| 24 | -1,008,619 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 25 | | PF Other Energy | | | | | | | | | | | | | | | |
| 26 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 27 | | | $6,266 | $8,556 | $9,722 | $8,015 | $6,748 | $6,226 | $5,690 | $4,927 | $2,866 | $5,142 | $5,838 | $6,583 | $76,579 | | |
| 28 | | **PF Partial Service** | $13,670 | $15,745 | $18,319 | $14,934 | $14,105 | $13,073 | $11,938 | $9,218 | $8,251 | $9,965 | $12,840 | $11,987 | $154,045 | | |
| 29 | | LLH Energy Flat | 292,812 | 376,569 | 407,646 | 401,531 | 334,706 | 324,762 | 322,760 | 347,741 | 290,928 | 307,350 | 294,113 | 296,931 | 3,997,849 | 456 | 3,998 |
| 30 | | HLH Energy Flat | 468,002 | 505,457 | 563,482 | 541,076 | 500,348 | 499,916 | 486,488 | 449,661 | 444,801 | 436,120 | 479,809 | 434,003 | 5,809,163 | 663 | 5,809 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $6,266 | $8,556 | $9,722 | $8,015 | $6,748 | $6,226 | $5,690 | $4,927 | $2,866 | $5,142 | $5,838 | $6,583 | $76,579 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $13,670 | $15,745 | $18,319 | $14,934 | $14,105 | $13,073 | $11,938 | $9,218 | $8,251 | $9,965 | $12,840 | $11,987 | $154,045 | | |
| 33 | | GSP Demand | 1,453 | 1,654 | 1,693 | 1,685 | 1,662 | 1,525 | 1,448 | 1,307 | 1,236 | 1,380 | 1,315 | 1,278 | 17,636 | | |
| 34 | | Demand Revenue (34*18) | $2,775 | $3,374 | $3,623 | $3,067 | $3,075 | $2,623 | $2,346 | $1,751 | $1,520 | $2,070 | $2,314 | $2,326 | $30,865 | | |
| 35 | | Load Variance | 1,010,835 | 1,134,069 | 1,251,375 | 1,220,046 | 1,087,221 | 1,090,317 | 1,060,987 | 1,049,283 | 988,300 | 987,361 | 1,011,512 | 961,639 | 12,852,945 | 1467 | 12853 |
| 36 | | Load Variance Revenue (36*21)/1000 | $465 | $522 | $576 | $561 | $500 | $502 | $488 | $483 | $455 | $454 | $465 | $442 | $5,912 | | |
| 37 | -1,133,980 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 38 | | PF Other Energy | | | | | | | | | | | | | | | |
| 39 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | $16,393 | $20,107 | $25,542 | $21,232 | $20,268 | $19,607 | $13,447 | $8,826 | $7,328 | $10,341 | $13,192 | $15,825 | $192,108 | | |
| 42 | | LLH Energy Flat | 391,915 | 520,023 | 577,456 | 609,659 | 514,460 | 520,497 | 381,897 | 340,167 | 281,881 | 339,246 | 376,183 | 428,295 | 5,281,679 | 603 | 5,282 |
| 43 | | HLH Energy Flat | 561,229 | 645,484 | 785,676 | 769,284 | 718,962 | 749,781 | 547,958 | 430,537 | 395,060 | 452,541 | 492,986 | 572,946 | 7,122,444 | 813 | 7,122 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $8,387 | $11,815 | $13,772 | $12,169 | $10,372 | $9,978 | $6,733 | $4,820 | $2,777 | $5,676 | $7,467 | $9,495 | $103,460 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $16,393 | $20,107 | $25,542 | $21,232 | $20,268 | $19,607 | $13,447 | $8,826 | $7,328 | $10,341 | $13,192 | $15,825 | $192,108 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,405 | 1,787 | 1,982 | 2,038 | 2,005 | 1,889 | 1,407 | 1,283 | 1,148 | 1,279 | 1,367 | 1,470 | 19,060 | | |
| 49 | | Demand Revenue (49*24) | $2,684 | $3,645 | $4,241 | $3,709 | $3,709 | $3,249 | $2,279 | $1,719 | $1,412 | $1,919 | $2,406 | $2,675 | $33,648 | | |
| 50 | -1,309,822 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.90% | -0.79% | -0.81% | -0.81% | -0.79% | -0.73% | -0.99% | -0.90% | -0.83% | -0.75% | -0.68% | -0.93% | | | |
| 53 | | Low-Density Discount | -$246 | -$282 | -$351 | -$302 | -$273 | -$240 | -$223 | -$138 | -$96 | -$135 | -$156 | -$260 | -$2,703 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | $1,333 | $1,601 | $2,424 | $2,491 | | $7,849 | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,975 | 39,179 | 0 | 152,052 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,414 | 65,334 | 73,164 | 64,012 | 0 | 247,924 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $805 | $836 | $1,557 | $1,746 | $0 | $4,944 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | | | | | | | | | | | | | | | |
| 62 | | **Pt Townsend HLH** | | | | | | | | | | | | | | | |
| 63 | | **Pt Townsend Demand** | | | | | | | | | | | | | | | |
| 64 | | **Pt Townsend Revenues** | | | | | | | | | | | | | | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF SLICE | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.51% | 1703 | |
| 68 | | 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 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $34,664 | $415,969 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 72 | | LDD Percentage | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | -1.15% | | | |
| 73 | | Low-Density Discount | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$4,799 | | |
| 74 | | Slice Other | | | | | | | | | | | | | | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,248 | 1,352 | 1,312 | 1,376 | 1,152 | 1,240 | 1,216 | 1,376 | 1,216 | 1,312 | 1,312 | 1,280 | 15,392 | 2 | 15 |
| 77 | | LLH Energy Revenue | $27 | $31 | $31 | $27 | $23 | $24 | $21 | $19 | $12 | $22 | $26 | $28 | $292 | | |
| 78 | | 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 |
| 79 | | HLH Energy Revenue | $50 | $48 | $54 | $44 | $43 | $45 | $41 | $33 | $31 | $38 | $45 | $44 | $516 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 4 | 8 | 4 | 4 | 4 | 8 | 4 | 56 | | |
| 81 | | Demand Revenue | | | | | | | | | | | | | $0 | | |
| 82 | | Load Variance | 2,976 | 2,888 | 2,976 | 2,976 | 2,688 | 2,968 | 2,880 | 2,976 | 2,880 | 2,976 | 2,976 | 2,880 | 35040 | 4 | 35 |
| 83 | | Load Variance Revenue | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $16 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | | | | | | | | | | | | | $0 | | |
| 88 | | **Total** | $106,689 | $125,124 | $141,378 | $124,570 | $117,303 | $111,224 | $95,771 | $80,672 | $70,964 | $86,376 | $98,419 | $102,102 | $1,260,592 | | |

## TABLE 4.6.1 REVENUE AT CURRENT RATES

| | A | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 17, 2009 @ 12:19 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | | **FY2011** | | | | | | | | | | | | |
| 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 | | **West Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | $2,834 | $3,268 | $3,689 | $3,272 | $3,221 | $2,707 | $2,274 | $1,458 | $1,306 | $1,652 | $1,843 | $1,891 | $29,416 | | |
| 10 | | LLH Energy Flat | 283,578 | 354,922 | 394,600 | 390,289 | 330,326 | 317,074 | 296,897 | 282,531 | 248,811 | 267,121 | 253,314 | 264,571 | 3,684,034 | 421 | 3684 |
| 11 | | HLH Energy Flat | 465,668 | 536,072 | 592,983 | 588,814 | 528,514 | 516,024 | 472,333 | 424,229 | 414,610 | 410,079 | 431,338 | 411,221 | 5,791,885 | 661 | 5792 |
| 12 | | 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 | | | |
| 13 | | 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 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $6,069 | $8,064 | $9,411 | $7,790 | $6,659 | $6,078 | $5,234 | $4,003 | $2,451 | $4,469 | $5,028 | $5,866 | $71,123 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $13,602 | $16,699 | $19,278 | $16,251 | $14,899 | $13,494 | $11,591 | $8,697 | $7,691 | $9,370 | $11,543 | $11,358 | $154,472 | | |
| 16 | | Demand | 1,484 | 1,602 | 1,724 | 1,798 | 1,741 | 1,574 | 1,404 | 1,088 | 1,062 | 1,101 | 1,047 | 1,039 | 16,664 | | |
| 17 | | 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 | | | |
| 18 | | Demand Revenue = 17*18 | $2,834 | $3,268 | $3,689 | $3,272 | $3,221 | $2,707 | $2,274 | $1,458 | $1,306 | $1,652 | $1,843 | $1,891 | $29,416 | | |
| 19 | | Load Variance | 769,662 | 913,492 | 1,013,058 | 1,003,535 | 881,143 | 855,669 | 793,774 | 734,170 | 689,789 | 702,458 | 709,091 | 695,357 | 9,761,198 | 1114 | 9761 |
| 20 | | 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 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $354 | $420 | $466 | $462 | $405 | $394 | $365 | $338 | $317 | $323 | $326 | $320 | $4,490 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -2.02% | -2.08% | -2.13% | -2.13% | -2.15% | -2.08% | -2.09% | -2.08% | -2.07% | -2.00% | -1.98% | -1.99% | | | |
| 23 | | Low Density Discount | -$462 | -$593 | -$698 | -$593 | -$541 | -$471 | -$408 | -$301 | -$243 | -$316 | -$371 | -$386 | -$5,382 | | |
| 24 | -1,008,619 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 25 | | PF Other Energy | | | | | | | | | | | | | | | |
| 26 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 27 | | | $6,643 | $8,460 | $9,810 | $8,157 | $6,883 | $6,352 | $5,808 | $5,016 | $2,923 | $5,312 | $5,764 | $6,717 | $77,846 | | |
| 28 | | **PF Partial Service** | $13,758 | $16,372 | $18,498 | $15,223 | $14,404 | $13,355 | $12,198 | $9,408 | $8,430 | $10,146 | $13,355 | $12,248 | $157,393 | | |
| 29 | | LLH Energy Flat | 310,434 | 372,366 | 411,304 | 408,670 | 341,401 | 331,376 | 329,438 | 354,011 | 296,778 | 317,507 | 290,391 | 302,982 | 4,066,658 | 464 | 4,067 |
| 30 | | HLH Energy Flat | 471,002 | 525,588 | 568,988 | 551,562 | 510,967 | 510,691 | 497,054 | 458,917 | 454,435 | 444,014 | 499,065 | 443,432 | 5,935,715 | 678 | 5,936 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $6,643 | $8,460 | $9,810 | $8,157 | $6,883 | $6,352 | $5,808 | $5,016 | $2,923 | $5,312 | $5,764 | $6,717 | $77,846 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $13,758 | $16,372 | $18,498 | $15,223 | $14,404 | $13,355 | $12,198 | $9,408 | $8,430 | $10,146 | $13,355 | $12,248 | $157,393 | | |
| 33 | | GSP Demand | 1,481 | 1,710 | 1,733 | 1,725 | 1,705 | 1,565 | 1,488 | 1,346 | 1,276 | 1,396 | 1,366 | 1,319 | 18,110 | | |
| 34 | | Demand Revenue (34*18) | $2,829 | $3,488 | $3,709 | $3,140 | $3,154 | $2,692 | $2,411 | $1,804 | $1,569 | $2,094 | $2,404 | $2,401 | $31,694 | | |
| 35 | | Load Variance | 1,031,458 | 1,150,010 | 1,260,540 | 1,237,670 | 1,104,535 | 1,107,706 | 1,078,232 | 1,064,810 | 1,003,784 | 1,005,411 | 1,027,047 | 977,119 | 13,048,322 | 1490 | 13048 |
| 36 | | Load Variance Revenue (36*21)/1000 | $474 | $529 | $580 | $569 | $508 | $510 | $496 | $490 | $462 | $462 | $472 | $449 | $6,002 | | |
| 37 | -1,133,980 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 38 | | PF Other Energy | | | | | | | | | | | | | | | |
| 39 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | $15,948 | $20,704 | $25,542 | $21,232 | $20,268 | $19,607 | $13,447 | $8,826 | $7,328 | $10,084 | $13,552 | $15,825 | $192,363 | | |
| 42 | | LLH Energy Flat | 407,170 | 501,586 | 577,456 | 609,659 | 514,460 | 520,497 | 381,897 | 340,167 | 281,881 | 353,957 | 359,890 | 428,295 | 5,276,915 | 602 | 5,277 |
| 43 | | HLH Energy Flat | 545,974 | 664,641 | 785,676 | 769,284 | 718,962 | 749,781 | 547,958 | 430,537 | 395,060 | 441,310 | 506,444 | 572,946 | 7,128,573 | 814 | 7,129 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $8,713 | $11,396 | $13,772 | $12,169 | $10,372 | $9,978 | $6,733 | $4,820 | $2,777 | $5,922 | $7,144 | $9,495 | $103,290 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $15,948 | $20,704 | $25,542 | $21,232 | $20,268 | $19,607 | $13,447 | $8,826 | $7,328 | $10,084 | $13,552 | $15,825 | $192,363 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,419 | 1,769 | 1,982 | 2,038 | 2,005 | 1,889 | 1,408 | 1,283 | 1,148 | 1,297 | 1,355 | 1,470 | 19,063 | | |
| 49 | | Demand Revenue (49*24) | $2,710 | $3,609 | $4,241 | $3,709 | $3,709 | $3,249 | $2,281 | $1,719 | $1,412 | $1,946 | $2,385 | $2,675 | $33,646 | | |
| 50 | -1,309,822 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.89% | -0.79% | -0.81% | -0.81% | -0.79% | -0.73% | -0.99% | -0.90% | -0.83% | -0.77% | -0.67% | -0.93% | | | |
| 53 | | Low-Density Discount | -$245 | -$284 | -$351 | -$302 | -$273 | -$240 | -$223 | -$138 | -$96 | -$138 | -$154 | -$260 | -$2,704 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | | | | | | | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,977 | 39,178 | 0 | 152,053 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,414 | 65,334 | 71,988 | 64,939 | 0 | 247,675 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $805 | $836 | $1,541 | $1,762 | $0 | $4,944 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | | | | | | | | | | | | | | | |
| 62 | | **Pt Townsend HLH** | | | | | | | | | | | | | | | |
| 63 | | **Pt Townsend Demand** | | | | | | | | | | | | | | | |
| 64 | | **Pt Townsend Revenues** | | | | | | | | | | | | | | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF SLICE | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.51% | 1690 | |
| 68 | | 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 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $435,916 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 72 | | LDD Percentage | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | | | |
| 73 | | Low-Density Discount | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$4,663 | | |
| 74 | | Slice Other | | | | | | | | | | | | | | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,312 | 1,288 | 1,312 | 1,376 | 1,152 | 1,240 | 1,216 | 1,376 | 1,216 | 1,376 | 0 | 0 | 12,864 | 1 | 13 |
| 77 | | LLH Energy Revenue | $27 | $27 | $27 | $29 | $24 | $26 | $25 | $29 | $25 | $29 | $0 | $0 | $267 | | |
| 78 | | 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 |
| 79 | | HLH Energy Revenue | $35 | $33 | $35 | $33 | $32 | $36 | $35 | $33 | $35 | $33 | $0 | $0 | $339 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 4 | 8 | 4 | 4 | 4 | 0 | 0 | 44 | | |
| 81 | | Demand Revenue | | | | | | | | | | | | | $0 | | |
| 82 | | Load Variance | 2,976 | 2,888 | 2,976 | 2,976 | 2,688 | 2,968 | 2,880 | 2,976 | 2,880 | 2,976 | 0 | 0 | 29184 | 3 | 29 |
| 83 | | Load Variance Revenue | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $13 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | | | | | | | | | | | | | $0 | | |
| 88 | | **Total** | $109,230 | $128,131 | $143,948 | $127,080 | $119,663 | $113,706 | $98,206 | $82,945 | $73,162 | $88,867 | $100,991 | $104,536 | $1,290,466 | | |

## TABLE 4.6.1 REVENUE AT CURRENT RATES

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 20, 2009 @ 10:19 | | Revenues at Current Rates | | | | | | | | | | | | | |
| 2 | | | Revenue ($ Thousands) | | | | | | | | | | | | | |
| 3 | | | **FY2009** | | | | | | | | | | | | | |
| 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 | $6,506 | $8,885 | $7,108 | $5,906 | $5,239 | $4,567 | $3,496 | $2,146 | $4,493 | $4,870 | $6,311 | $64,894 | | |
| 9 | East Hub PF Billing Determinants | $11,917 | $11,762 | $17,209 | $14,011 | $12,160 | $11,143 | $10,015 | $7,231 | $6,659 | $9,099 | $10,793 | $11,749 | $133,748 | | |
| 10 | **PF Full Service** | $2,227 | $2,235 | $3,639 | $2,596 | $2,579 | $2,093 | $1,874 | $1,489 | $1,396 | $2,351 | $2,409 | $2,324 | $27,212 | | |
| 11 | LLH Energy Flat | 250,844 | 286,353 | 372,533 | 356,091 | 292,954 | 273,287 | 259,029 | 246,688 | 217,862 | 268,559 | 245,333 | 284,685 | 3,354,218 | 383 | 3,354 |
| 12 | HLH Energy Flat | 407,981 | 377,601 | 529,332 | 507,651 | 431,350 | 426,128 | 408,092 | 352,756 | 358,976 | 398,206 | 403,309 | 425,382 | 5,026,764 | 574 | 5,027 |
| 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)/100 | $5,368 | $6,506 | $8,884 | $7,108 | $5,906 | $5,239 | $4,567 | $3,496 | $2,146 | $4,493 | $4,870 | $6,311 | $64,893 | | |
| 16 | HLH Energy Revenue Flat= (12*14)/100 | $11,917 | $11,762 | $17,200 | $14,011 | $12,160 | $11,143 | $10,015 | $7,231 | $6,659 | $9,099 | $10,793 | $11,749 | $133,739 | | |
| 17 | GSP Demand | 1,166 | 1,095 | 1,701 | 1,426 | 1,394 | 1,217 | 1,157 | 1,111 | 1,135 | 1,567 | 1,369 | 1,277 | 15,615 | 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= (18*17 | $2,227 | $2,235 | $3,638 | $2,596 | $2,579 | $2,093 | $1,875 | $1,488 | $1,396 | $2,350 | $2,410 | $2,325 | $27,213 | | |
| 20 | PF Ld Variance | 666,394 | 672,419 | 910,999 | 872,428 | 729,881 | 702,637 | 671,689 | 756,946 | 799,339 | 918,757 | 865,138 | 712,436 | 9,279,063 | 1,059 | 9,279 |
| 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= (20*21)/1000 | $307 | $309 | $419 | $401 | $336 | $323 | $309 | $307 | $308 | $360 | $343 | $327 | $4,049 | | |
| 23 | Low Density Discount Percent=28/(15+16+2 | -3.83% | -3.66% | -3.75% | -3.73% | -3.67% | -3.70% | -3.98% | -3.71% | -3.52% | -3.55% | -3.55% | -4.07% | | | |
| 24 | Low Density Discount | -$758 | -$761 | -$1,131 | -$900 | -$770 | -$696 | -$667 | -$465 | -$370 | -$578 | -$653 | -$842 | -$8,591 | | |
| 25 | LBCRAC True-up/Lookback Adjus | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$7,235 | | |
| 26 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 27 | PF Other Revenues | -$169 | $0 | $0 | $0 | $0 | | | | | | | | -$169 | | |
| 28 | | $1,709 | $2,063 | $2,680 | $2,153 | $1,822 | $1,761 | $1,425 | $1,126 | $745 | $1,549 | $1,638 | $1,903 | $20,575 | | |
| 29 | **PF Partial Service** | $3,724 | $3,683 | $5,158 | $4,195 | $3,754 | $3,627 | $2,931 | $2,248 | $2,248 | $3,000 | $3,534 | $3,374 | $41,475 | | |
| 30 | LLH Energy Flat | 79,872 | 90,795 | 112,377 | 107,878 | 90,396 | 91,865 | 80,822 | 79,443 | 75,667 | 92,580 | 82,528 | 85,852 | 1,070,075 | 122 | 1,070 |
| 31 | HLH Energy Flat | 127,480 | 118,245 | 158,653 | 151,997 | 133,163 | 138,684 | 119,422 | 109,656 | 121,177 | 131,293 | 132,068 | 122,171 | 1,564,009 | 179 | 1,564 |
| 32 | LLH Energy Revenue Flat = 30*13/100 | $1,709 | $2,063 | $2,680 | $2,153 | $1,822 | $1,761 | $1,425 | $1,126 | $745 | $1,549 | $1,638 | $1,903 | $20,575 | | |
| 33 | HLH Energy Revenue Flat = 31*14/100 | $3,724 | $3,683 | $5,158 | $4,195 | $3,754 | $3,627 | $2,931 | $2,248 | $2,248 | $3,000 | $3,534 | $3,374 | $41,475 | | |
| 34 | GSP Demand | 342 | 328 | 481 | 440 | 406 | 355 | 331 | 269 | 290 | 337 | 325 | 297 | 4,202 | | |
| 35 | Demand Revenue = 34*17 | $654 | $669 | $1,030 | $801 | $752 | $611 | $536 | $360 | $357 | $506 | $572 | $541 | $7,388 | | |
| 36 | Load Variance | 214,856 | 216,324 | 270,370 | 259,854 | 222,876 | 218,741 | 193,179 | 184,753 | 196,567 | 223,003 | 209,678 | 194,364 | 2,604,565 | 297 | 2,605 |
| 37 | Load Variance = 36*21/1000 | $99 | $100 | $128 | $123 | $103 | $101 | $89 | $85 | $90 | $103 | $96 | $89 | $1,205 | | |
| 38 | LBCRAC True-up/Lookback Adjus | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$2,252 | | |
| 39 | Low Density Discount Percent= 56/(42+43+4 | -2.69% | -2.65% | -2.36% | -2.37% | -2.51% | -2.34% | -2.35% | -2.31% | -2.43% | -2.41% | -2.46% | -2.66% | | | |
| 40 | Low Density Discount | -$167 | -$173 | -$212 | -$172 | -$161 | -$143 | -$117 | -$88 | -$84 | -$124 | -$144 | -$157 | -$1,742 | | |
| 41 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 42 | PF Other Revenue | $0 | $0 | $3 | $3 | $2 | | | | | | | | $8 | | |
| 43 | | $2,450 | $2,894 | $3,207 | $2,724 | $2,380 | $2,158 | $2,208 | $1,801 | $1,052 | $1,838 | $1,923 | $2,618 | $27,255 | | |
| 44 | **PF Block Service** | $4,719 | $4,605 | $5,640 | $4,857 | $4,514 | $3,737 | $4,202 | $2,682 | $2,441 | $2,709 | $2,860 | $4,070 | $47,036 | | |
| 45 | LLH Energy Flat | 114,504 | 127,386 | 134,480 | 136,448 | 118,080 | 112,587 | 125,243 | 127,087 | 106,824 | 109,867 | 96,891 | 118,103 | 1,427,500 | 163 | 1,428 |
| 46 | HLH Energy Flat | 161,568 | 147,840 | 173,472 | 175,968 | 160,128 | 142,900 | 171,239 | 130,828 | 131,616 | 118,569 | 106,867 | 147,340 | 1,768,335 | 202 | 1,768 |
| 47 | LLH Energy Revenue Flat=(45*13)/100 | $2,450 | $2,894 | $3,207 | $2,724 | $2,380 | $2,158 | $2,208 | $1,801 | $1,052 | $1,838 | $1,923 | $2,618 | $27,255 | | |
| 48 | HLH Energy Revenue Flat=(46*14)/100 | $4,719 | $4,605 | $5,640 | $4,857 | $4,514 | $3,737 | $4,202 | $2,682 | $2,441 | $2,709 | $2,860 | $4,070 | $47,036 | | |
| 49 | GSP Demand | 374 | 385 | 417 | 423 | 417 | 341 | 403 | 457 | 500 | 495 | 413 | 368 | 4,993 | | |
| 50 | Demand Revenue=(49*24 | $714 | $785 | $892 | $770 | $771 | $587 | $653 | $613 | $614 | $742 | $727 | $669 | $8,539 | | |
| 51 | LBCRAC True-up/Lookback Adjus | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$3,840 | | |
| 52 | Low-Density Discount | $0 | $0 | $0 | $0 | $0 | | | | | | | | $0 | | |
| 53 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 54 | PF Block Other Revenue | $0 | $0 | $0 | $0 | $0 | | | | | | | | | | |
| 55 | | | | | | | | | | | | | | | | |
| 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 | $92,568 | | |
| 57 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 349 | |
| 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 = 57*58*100 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $92,564 | | |
| 60 | LBCRAC True-up/Lookback Adjus | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$2,915 | | |
| 61 | Slice Other Revenues | $0 | $0 | -$286 | $0 | $0 | | | | | | | | -$285 | | |
| 62 | | | | | | | | | | | | | | | | |
| 63 | **East Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 64 | LLH Energy Pre-Sub | 36,570 | 45,106 | 64,189 | 60,054 | 47,683 | 55,768 | 48,804 | 50,954 | 48,701 | 61,609 | 52,733 | 48,484 | 620,655 | 71 | 621 |
| 65 | LLH Energy Revenue | $819 | $1,013 | $1,444 | $1,355 | $1,077 | $1,162 | $902 | $524 | $448 | $780 | $903 | $1,019 | $11,447 | | |
| 66 | HLH Energy Pre-Sub | 60,392 | 60,156 | 90,776 | 85,239 | 71,334 | 87,630 | 74,790 | 75,799 | 83,085 | 91,980 | 92,307 | 72,031 | 945,519 | 108 | 946 |
| 67 | HLH Energy Revenue | $1,485 | $1,478 | $2,236 | $2,095 | $1,758 | $2,012 | $1,542 | $953 | $985 | $1,403 | $1,877 | $1,667 | $19,491 | | |
| 68 | GSP Demand | 176 | 182 | 308 | 262 | 223 | 234 | 214 | 186 | 192 | 245 | 229 | 200 | 2,651 | | |
| 69 | Demand Revenue | $169 | $170 | $280 | $230 | $199 | $241 | $213 | $176 | $176 | $241 | $235 | $204 | $2,535 | | |
| 70 | Load Variance | 78,157 | 80,377 | 114,002 | 105,127 | 86,046 | 137,710 | 119,954 | 121,940 | 123,478 | 149,025 | 140,209 | 117,755 | 1,373,780 | 157 | 1,374 |
| 71 | Load Variance Revenue | $45 | $47 | $66 | $61 | $50 | $78 | $68 | $70 | $70 | $85 | $80 | $67 | $787 | | |
| 72 | Low Density Discount Percen | -2.77% | -2.84% | -2.60% | -2.79% | -2.82% | -5.00% | -4.93% | -4.57% | -4.74% | -4.73% | -4.83% | -4.97% | | | |
| 73 | Low Density Discount | -$70 | -$77 | -$105 | -$104 | -$87 | -$175 | -$134 | -$79 | -$80 | -$119 | -$150 | -$147 | -$1,325 | | |
| 74 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 75 | Other Presubscription revenues | $2 | $2 | $3 | $3 | $2 | | | | | | | | $13 | | |
| 76 | **Irrigation Mitigation** | | | | | | $0 | $0 | $4,336 | $5,308 | $8,144 | $7,986 | | $25,775 | | |
| 77 | Irrigation Mitigation LLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 92,652 | 128,555 | 154,155 | 123,083 | 0 | 498,445 | 57 | 498 |
| 78 | Irrigation Mitigation HLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 147,478 | 217,906 | 243,565 | 207,128 | 0 | 816,077 | 93 | 816 |
| 79 | Irrigation Mitigation Flat Revenues | $0 | $0 | $0 | $0 | -$3 | $0 | $0 | $1,259 | $1,411 | $2,649 | $2,875 | $0 | $8,191 | | |
| 80 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | -$5 | $0 | $0 | $1,293 | $1,325 | $2,497 | $2,529 | $0 | $7,639 | | |
| 81 | Total | $41,605 | $43,673 | $57,535 | $48,671 | $43,500 | $40,219 | $36,975 | $31,441 | $28,300 | $39,943 | $43,679 | $42,149 | $497,689 | | |

**TABLE 4.6.1 REVENUE AT CURRENT RATES**

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 20, 2009 @ 10:19 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2010** | | | | | | | | | | | | |
| 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 | | $5,498 | $6,817 | $8,708 | $7,382 | $5,959 | $5,192 | $4,646 | $3,511 | $2,178 | $4,842 | $4,904 | $6,382 | $66,019 | | |
| 9 | East Hub PF Billing Determinants | $11,974 | $13,291 | $16,631 | $14,494 | $12,582 | $11,121 | $9,907 | $7,374 | $6,552 | $8,656 | $10,777 | $11,739 | $135,098 | | |
| 10 | **PF Full Service** | $2,273 | $2,444 | $3,007 | $2,706 | $2,579 | $1,973 | $1,733 | $1,395 | $1,396 | $2,183 | $2,369 | $2,188 | $26,245 | | |
| 11 | LLH Energy Flat | 256,926 | 300,030 | 365,105 | 369,853 | 295,572 | 270,818 | 263,535 | 247,807 | 221,089 | 289,424 | 247,039 | 287,876 | 3,415,074 | 390 | 3,415 |
| 12 | HLH Energy Flat | 409,926 | 426,668 | 511,562 | 525,154 | 446,340 | 425,282 | 403,695 | 359,686 | 353,216 | 378,836 | 402,715 | 425,019 | 5,068,099 | 579 | 5,068 |
| 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)/100 | $5,498 | $6,817 | $8,708 | $7,382 | $5,959 | $5,192 | $4,646 | $3,511 | $2,178 | $4,842 | $4,904 | $6,382 | $66,019 | | |
| 16 | HLH Energy Revenue Flat= (12*14)/100 | $11,974 | $13,291 | $16,631 | $14,494 | $12,582 | $11,121 | $9,907 | $7,374 | $6,552 | $8,656 | $10,777 | $11,739 | $135,098 | | |
| 17 | GSP Demand | 1,190 | 1,198 | 1,405 | 1,487 | 1,394 | 1,147 | 1,070 | 1,041 | 1,135 | 1,455 | 1,346 | 1,202 | 15,070 | | |
| 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= (18*17 | $2,273 | $2,444 | $3,007 | $2,706 | $2,579 | $1,973 | $1,733 | $1,395 | $1,396 | $2,183 | $2,369 | $2,188 | $26,245 | | |
| 20 | PF Ld Variance | 669,814 | 730,157 | 878,853 | 895,914 | 743,124 | 698,937 | 671,474 | 764,764 | 796,577 | 919,892 | 865,875 | 714,885 | 9,350,266 | 1,067 | 9,350 |
| 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= (20*21)/1000 | $328 | $357 | $430 | $439 | $364 | $342 | $329 | $331 | $327 | $384 | $366 | $350 | $4,347 | | |
| 23 | Low Density Discount Percent=28/(15+16+2 | -3.86% | -3.70% | -3.73% | -3.71% | -3.70% | -3.73% | -3.96% | -3.73% | -3.54% | -3.55% | -3.54% | -4.09% | | | |
| 24 | Low Density Discount | -$775 | -$847 | -$1,073 | -$929 | -$794 | -$694 | -$658 | -$471 | -$371 | -$570 | -$653 | -$846 | -$8,679 | | |
| 25 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 26 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 27 | PF Other Revenues | | | | | | | | | | | | | | | |
| 28 | | $1,739 | $2,180 | $2,606 | $2,246 | $1,843 | $1,679 | $1,376 | $1,051 | $721 | $1,518 | $1,556 | $1,766 | $20,281 | | |
| 29 | **PF Partial Service** | $3,698 | $4,124 | $4,746 | $4,313 | $3,814 | $3,455 | $2,821 | $2,140 | $2,135 | $2,808 | $3,297 | $3,155 | $40,505 | | |
| 30 | LLH Energy Flat | 81,285 | 95,941 | 109,282 | 112,511 | 91,394 | 87,582 | 78,065 | 74,172 | 73,207 | 90,707 | 78,372 | 79,662 | 1,052,180 | 120 | 1,052 |
| 31 | HLH Energy Flat | 126,584 | 132,407 | 145,989 | 156,269 | 135,279 | 132,110 | 114,972 | 104,371 | 115,090 | 122,891 | 123,207 | 114,213 | 1,523,382 | 174 | 1,523 |
| 32 | LLH Energy Revenue Flat = 30*13/100 | $1,739 | $2,180 | $2,606 | $2,246 | $1,843 | $1,679 | $1,376 | $1,051 | $721 | $1,518 | $1,556 | $1,766 | $20,281 | | |
| 33 | HLH Energy Revenue Flat = 31*14/100 | $3,698 | $4,124 | $4,746 | $4,313 | $3,814 | $3,455 | $2,821 | $2,140 | $2,135 | $2,808 | $3,297 | $3,155 | $40,505 | | |
| 34 | GSP Demand | 365 | 358 | 432 | 445 | 406 | 355 | 348 | 285 | 313 | 355 | 322 | 303 | 4,287 | | |
| 35 | Demand Revenue = 34*17 | $697 | $730 | $924 | $810 | $751 | $611 | $564 | $382 | $385 | $533 | $567 | $551 | $7,505 | | |
| 36 | Load Variance | 214,933 | 234,662 | 262,188 | 272,047 | 231,849 | 225,819 | 199,704 | 190,292 | 201,838 | 229,265 | 216,449 | 200,638 | 2,679,684 | 306 | 2,680 |
| 37 | Load Variance = 36*21/1000 | $99 | $108 | $121 | $125 | $107 | $104 | $92 | $88 | $93 | $105 | $100 | $92 | $1,233 | | |
| 38 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 39 | Low Density Discount Percent= 56/(42+43+4 | -2.62% | -2.50% | -2.45% | -2.38% | -2.42% | -2.41% | -2.46% | -2.37% | -2.55% | -2.52% | -2.52% | -2.67% | | | |
| 40 | Low Density Discount | -$163 | -$178 | -$206 | -$178 | -$158 | -$141 | -$119 | -$87 | -$85 | -$125 | -$139 | -$149 | -$1,727 | | |
| 41 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 42 | PF Other Revenue | -$107 | -$117 | -$131 | -$136 | -$116 | -$113 | -$100 | -$95 | -$101 | -$115 | -$108 | -$100 | -$1,340 | | |
| 43 | | $2,272 | $2,642 | $2,931 | $2,616 | $2,218 | $2,051 | $2,208 | $1,779 | $1,048 | $1,838 | $1,928 | $2,618 | $26,150 | | |
| 44 | **PF Block Service** | $4,288 | $4,114 | $5,057 | $4,192 | $4,127 | $3,884 | $4,202 | $2,681 | $2,441 | $2,709 | $2,871 | $4,070 | $44,636 | | |
| 45 | LLH Energy Flat | 106,189 | 116,270 | 122,909 | 131,065 | 110,031 | 106,978 | 125,243 | 125,535 | 106,388 | 109,867 | 97,150 | 118,103 | 1,375,728 | 157 | 1,376 |
| 46 | HLH Energy Flat | 146,812 | 132,060 | 155,543 | 151,870 | 146,410 | 148,510 | 171,239 | 130,786 | 131,616 | 118,569 | 107,283 | 147,340 | 1,688,038 | 193 | 1,688 |
| 47 | LLH Energy Revenue Flat=(45*13)/100 | $2,272 | $2,642 | $2,931 | $2,616 | $2,218 | $2,051 | $2,208 | $1,779 | $1,048 | $1,838 | $1,928 | $2,618 | $26,150 | | |
| 48 | HLH Energy Revenue Flat=(46*14)/100 | $4,288 | $4,114 | $5,057 | $4,192 | $4,127 | $3,884 | $4,202 | $2,681 | $2,441 | $2,709 | $2,871 | $4,070 | $44,636 | | |
| 49 | GSP Demand | 338 | 342 | 372 | 377 | 379 | 341 | 403 | 457 | 500 | 495 | 414 | 368 | 4,786 | | |
| 50 | Demand Revenue=(49*24 | $646 | $698 | $796 | $686 | $701 | $587 | $653 | $612 | $615 | $743 | $729 | $670 | $8,134 | | |
| 51 | LBCRAC True-up/Lookback Adjus | $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** | | | | | | | | | | | | | | | |
| 57 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 379 | |
| 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 = 57*58*100 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $97,004 | | |
| 60 | LBCRAC True-up/Lookback Adjus | $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 | 48,311 | 59,076 | 71,350 | 71,090 | 59,268 | 57,319 | 50,063 | 50,774 | 48,422 | 64,168 | 53,122 | 48,854 | 681,817 | 78 | 682 |
| 65 | LLH Energy Revenue | $1,034 | $1,342 | $1,702 | $1,419 | $1,195 | $1,099 | $883 | $719 | $477 | $1,074 | $1,054 | $1,083 | $13,080 | | |
| 66 | HLH Energy Pre-Sub | 76,790 | 85,495 | 100,471 | 102,743 | 89,919 | 89,482 | 75,692 | 76,506 | 81,603 | 87,731 | 91,807 | 72,242 | 1,030,481 | 118 | 1,030 |
| 67 | HLH Energy Revenue | $2,243 | $2,663 | $3,266 | $2,836 | $2,535 | $2,340 | $1,857 | $1,568 | $1,514 | $2,005 | $2,457 | $1,995 | $27,279 | | |
| 68 | GSP Demand | 229 | 239 | 289 | 307 | 281 | 241 | 221 | 191 | 207 | 253 | 235 | 201 | 2,894 | | |
| 69 | Demand Revenue | $437 | $488 | $618 | $559 | $520 | $415 | $358 | $256 | $255 | $380 | $414 | $366 | $5,064 | | |
| 70 | Load Variance | 122,499 | 138,070 | 166,468 | 168,993 | 142,704 | 141,213 | 124,113 | 124,263 | 125,985 | 148,512 | 141,713 | 119,780 | 1,664,313 | 190 | 1,664 |
| 71 | Load Variance Revenue | $56 | $64 | $77 | $78 | $66 | $65 | $57 | $57 | $58 | $68 | $65 | $55 | $766 | | |
| 72 | Low Density Discount Percen | -4.00% | -3.89% | -3.79% | -4.56% | -4.42% | -4.60% | -4.45% | -3.09% | -3.56% | -3.35% | -3.79% | -4.26% | | | |
| 73 | Low Density Discount | -$151 | -$177 | -$214 | -$223 | -$191 | -$180 | -$140 | -$80 | -$82 | -$118 | -$151 | -$149 | -$1,858 | | |
| 74 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 75 | Other Presubscription revenues | | | | | | | | | | | | | $0 | | |
| 76 | **Irrigation Mitigation** | | | | | | $0 | $0 | $4,203 | $5,137 | $7,860 | $7,739 | | $24,939 | | |
| 77 | Irrigation Mitigation LLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90,110 | 124,006 | 147,923 | 118,453 | 0 | 480,492 | 55 | 480 |
| 78 | Irrigation Mitigation HLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 142,759 | 211,084 | 235,661 | 201,328 | 0 | 790,832 | 90 | 791 |
| 79 | Irrigation Mitigation Flat Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,321 | $1,500 | $2,737 | $2,979 | $0 | $8,537 | | |
| 80 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,451 | $1,509 | $2,783 | $2,797 | $0 | $8,540 | | |
| 81 | Total | $44,170 | $48,825 | $58,080 | $51,518 | $46,184 | $41,871 | $38,752 | $34,068 | $30,649 | $42,521 | $46,260 | $43,920 | $526,819 | | |

**TABLE 4.6.1 REVENUE AT CURRENT RATES**

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 20, 2009 @ 10:19 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2011** | | | | | | | | | | | | |
| 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 | | $5,679 | $6,916 | $8,897 | $7,530 | $6,093 | $5,313 | $4,753 | $3,605 | $2,237 | $4,763 | $4,970 | $6,523 | $67,279 | | |
| 9 | East Hub PF Billing Determinants | $12,160 | $13,667 | $16,970 | $14,772 | $12,857 | $11,375 | $10,129 | $7,571 | $6,733 | $9,208 | $11,157 | $11,995 | $138,593 | | |
| 10 | **PF Full Service** | $2,323 | $2,499 | $3,073 | $2,761 | $2,638 | $2,018 | $1,772 | $1,424 | $1,423 | $2,219 | $2,415 | $2,233 | $26,797 | | |
| 11 | LLH Energy Flat | 265,363 | 304,387 | 373,047 | 377,242 | 302,236 | 277,167 | 269,587 | 254,440 | 227,103 | 284,701 | 250,391 | 294,218 | 3,479,882 | 397 | 3,480 |
| 12 | HLH Energy Flat | 416,290 | 438,749 | 521,990 | 535,221 | 456,078 | 435,003 | 412,742 | 369,302 | 362,987 | 402,968 | 416,923 | 434,274 | 5,202,527 | 594 | 5,203 |
| 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)/100 | $5,679 | $6,916 | $8,897 | $7,530 | $6,093 | $5,313 | $4,753 | $3,605 | $2,237 | $4,763 | $4,970 | $6,523 | $67,279 | | |
| 16 | HLH Energy Revenue Flat= (12*14)/100 | $12,160 | $13,667 | $16,970 | $14,772 | $12,857 | $11,375 | $10,129 | $7,571 | $6,733 | $9,208 | $11,157 | $11,995 | $138,593 | | |
| 17 | GSP Demand | 1,216 | 1,225 | 1,436 | 1,517 | 1,426 | 1,173 | 1,094 | 1,063 | 1,157 | 1,479 | 1,372 | 1,227 | 15,385 | | |
| 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= (18*17 | $2,323 | $2,499 | $3,073 | $2,761 | $2,638 | $2,018 | $1,772 | $1,424 | $1,423 | $2,219 | $2,415 | $2,233 | $26,797 | | |
| 20 | PF Ld Variance | 684,415 | 746,400 | 897,023 | 913,370 | 759,525 | 715,007 | 686,764 | 781,073 | 812,604 | 939,584 | 883,433 | 730,482 | 9,549,680 | 1,090 | 9,550 |
| 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= (20*21)/1000 | $335 | $365 | $439 | $447 | $372 | $350 | $336 | $339 | $335 | $394 | $374 | $358 | $4,444 | | |
| 23 | Low Density Discount Percent=28/(15+16+2 | -3.86% | -3.70% | -3.73% | -3.72% | -3.70% | -3.73% | -3.96% | -3.74% | -3.56% | -3.56% | -3.56% | -4.09% | | | |
| 24 | Low Density Discount | -$792 | -$869 | -$1,097 | -$948 | -$813 | -$710 | -$673 | -$484 | -$382 | -$591 | -$673 | -$863 | -$8,894 | | |
| 25 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 26 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 27 | PF Other Revenues | | | | | | | | | | | | | $0 | | |
| 28 | | $1,825 | $2,215 | $2,689 | $2,315 | $1,901 | $1,733 | $1,423 | $1,083 | $741 | $1,534 | $1,579 | $1,823 | $20,861 | | |
| 29 | **PF Partial Service** | $3,779 | $4,304 | $4,898 | $4,452 | $3,939 | $3,569 | $2,919 | $2,208 | $2,196 | $2,947 | $3,450 | $3,260 | $41,920 | | |
| 30 | LLH Energy Flat | 85,264 | 97,487 | 112,736 | 115,966 | 94,307 | 90,408 | 80,720 | 76,449 | 75,245 | 91,685 | 79,545 | 82,221 | 1,082,033 | 124 | 1,082 |
| 31 | HLH Energy Flat | 129,384 | 138,166 | 150,669 | 161,287 | 139,722 | 136,475 | 118,944 | 107,717 | 118,399 | 128,953 | 128,908 | 118,022 | 1,576,646 | 180 | 1,577 |
| 32 | LLH Energy Revenue Flat = 30*13/100 | $1,825 | $2,215 | $2,689 | $2,315 | $1,901 | $1,733 | $1,423 | $1,083 | $741 | $1,534 | $1,579 | $1,823 | $20,861 | | |
| 33 | HLH Energy Revenue Flat = 31*14/100 | $3,779 | $4,304 | $4,898 | $4,452 | $3,939 | $3,569 | $2,919 | $2,208 | $2,196 | $2,947 | $3,450 | $3,260 | $41,920 | | |
| 34 | GSP Demand | 377 | 369 | 446 | 459 | 419 | 367 | 360 | 294 | 322 | 366 | 333 | 313 | 4,425 | | |
| 35 | Demand Revenue = 34*17 | $720 | $753 | $954 | $835 | $775 | $631 | $583 | $394 | $396 | $549 | $586 | $570 | $7,747 | | |
| 36 | Load Variance | 221,712 | 241,968 | 270,323 | 280,520 | 239,205 | 233,009 | 206,330 | 195,915 | 207,185 | 236,306 | 223,324 | 207,006 | 2,762,803 | 315 | 2,763 |
| 37 | Load Variance = 36*21/1000 | $102 | $111 | $124 | $129 | $110 | $107 | $95 | $90 | $95 | $109 | $103 | $95 | $1,271 | | |
| 38 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 39 | Low Density Discount Percent= 56/(42+43+4 | -2.57% | -2.46% | -2.41% | -2.34% | -2.38% | -2.37% | -2.42% | -2.34% | -2.52% | -2.47% | -2.48% | -2.63% | | | |
| 40 | Low Density Discount | -$165 | -$182 | -$209 | -$181 | -$160 | -$143 | -$121 | -$88 | -$87 | -$127 | -$142 | -$151 | -$1,757 | | |
| 41 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 42 | PF Other Revenue | -$111 | -$121 | -$135 | -$140 | -$120 | -$117 | -$103 | -$98 | -$104 | -$118 | -$112 | -$104 | -$1,381 | | |
| 43 | | $2,390 | $2,514 | $2,931 | $2,616 | $2,218 | $2,051 | $2,208 | $1,779 | $1,048 | $1,967 | $1,799 | $2,618 | $26,140 | | |
| 44 | **PF Block Service** | $4,128 | $4,288 | $5,057 | $4,192 | $4,127 | $3,884 | $4,202 | $2,681 | $2,441 | $2,554 | $3,045 | $4,070 | $44,668 | | |
| 45 | LLH Energy Flat | 111,697 | 110,670 | 122,909 | 131,065 | 110,031 | 106,978 | 125,243 | 125,535 | 106,388 | 117,561 | 90,638 | 118,103 | 1,376,818 | 157 | 1,377 |
| 46 | HLH Energy Flat | 141,305 | 137,660 | 155,543 | 151,870 | 146,410 | 148,510 | 171,239 | 130,786 | 131,616 | 111,758 | 113,795 | 147,340 | 1,687,832 | 193 | 1,688 |
| 47 | LLH Energy Revenue Flat=(45*13)/100 | $2,390 | $2,514 | $2,931 | $2,616 | $2,218 | $2,051 | $2,208 | $1,779 | $1,048 | $1,967 | $1,799 | $2,618 | $26,140 | | |
| 48 | HLH Energy Revenue Flat=(46*14)/100 | $4,128 | $4,288 | $5,057 | $4,192 | $4,127 | $3,884 | $4,202 | $2,681 | $2,441 | $2,554 | $3,045 | $4,070 | $44,668 | | |
| 49 | GSP Demand | 338 | 342 | 372 | 377 | 379 | 341 | 403 | 457 | 500 | 495 | 414 | 368 | 4,786 | | |
| 50 | Demand Revenue=(49*24 | $646 | $698 | $796 | $686 | $701 | $587 | $653 | $612 | $615 | $743 | $729 | $670 | $8,134 | | |
| 51 | LBCRAC True-up/Lookback Adjus | $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** | | | | | | | | | | | | | | | |
| 57 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 376 | |
| 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 = 57*58*100 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $92,568 | | |
| 60 | LBCRAC True-up/Lookback Adjus | $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** | -3.52% | -3.46% | -3.39% | -4.05% | -3.93% | -4.13% | -3.93% | -2.78% | -3.19% | -2.96% | -3.30% | -3.75% | | | |
| 64 | LLH Energy Pre-Sub | 48,808 | 59,694 | 71,524 | 71,208 | 59,272 | 57,502 | 50,596 | 51,333 | 48,917 | 62,298 | 54,173 | 49,844 | 685,169 | 78 | 685 |
| 65 | LLH Energy Revenue | $1,044 | $1,356 | $1,706 | $1,421 | $1,195 | $1,102 | $892 | $727 | $482 | $1,042 | $1,075 | $1,105 | $13,149 | | |
| 66 | HLH Energy Pre-Sub | 77,645 | 86,476 | 100,821 | 103,157 | 91,001 | 90,468 | 76,547 | 77,373 | 82,498 | 92,686 | 93,889 | 73,661 | 1,046,222 | 119 | 1,046 |
| 67 | HLH Energy Revenue | $2,268 | $2,694 | $3,278 | $2,847 | $2,565 | $2,366 | $1,878 | $1,586 | $1,530 | $2,118 | $2,512 | $2,035 | $27,677 | | |
| 68 | GSP Demand | 232 | 243 | 293 | 311 | 285 | 246 | 225 | 194 | 210 | 256 | 238 | 204 | 2,937 | | |
| 69 | Demand Revenue | $443 | $496 | $627 | $566 | $527 | $423 | $365 | $260 | $258 | $384 | $419 | $371 | $5,139 | | |
| 70 | Load Variance | 124,612 | 140,485 | 169,313 | 171,850 | 145,233 | 143,629 | 126,284 | 126,466 | 128,173 | 151,230 | 144,127 | 121,860 | 1,693,262 | 193 | 1,693 |
| 71 | Load Variance Revenue | $57 | $65 | $78 | $79 | $67 | $66 | $58 | $58 | $59 | $70 | $66 | $56 | $779 | | |
| 72 | Low Density Discount Percen | -3.52% | -3.46% | -3.39% | -4.05% | -3.93% | -4.13% | -3.93% | -2.78% | -3.19% | -2.96% | -3.30% | -3.75% | | | |
| 73 | Low Density Discount | -$134 | -$160 | -$193 | -$199 | -$171 | -$163 | -$126 | -$73 | -$74 | -$107 | -$135 | -$134 | -$1,669 | | |
| 74 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 75 | Other Presubscription revenues | | | | | | | | | | | | | $0 | | |
| 76 | **Irrigation Mitigation** | | | | | | | | | | | | | | | |
| 77 | Irrigation Mitigation LLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90,110 | 124,006 | 148,154 | 117,248 | 0 | 479,518 | 55 | 480 |
| 78 | Irrigation Mitigation HLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 142,759 | 211,084 | 234,548 | 199,640 | 0 | 788,031 | 90 | 788 |
| 79 | Irrigation Mitigation Flat Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,321 | $1,500 | $2,737 | $2,924 | $0 | $8,482 | | |
| 80 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,451 | $1,509 | $2,769 | $2,797 | $0 | $8,527 | | |
| 81 | Total | $44,410 | $49,323 | $58,598 | $51,893 | $46,537 | $42,155 | $38,957 | $34,163 | $30,668 | $42,875 | $46,652 | $44,242 | $530,475 | | |

# TABLE 4.6.1 REVENUE AT CURRENT RATES

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2009** | | | | | | | | | | | | |
| 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (46.46) | (46.46) | (46.46) | (47.22) | ($47.45) | (47.45) | (47.56) | (47.56) | (47.67) | (47.67) | (48.00) | (48.00) | (49.46) | | |
| 10 | Energy (MWhr) | 2,357,543 | 2,669,837 | 3,476,522 | 4,317,495 | 3,368,129 | 3,127,975 | 2,701,817 | 2,484,845 | 2,481,228 | 2,644,717 | 2,528,174 | 2,314,738 | 34,473,020 | 3,935 | 34,473 |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$113,539 | -$129,016 | -$167,543 | -$213,478 | -$168,287 | -$156,379 | -$135,368 | -$123,944 | -$123,530 | -$130,913 | -$126,651 | -$116,493 | -$1,705,142 | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | | | | | | | | | | | | | | | |
| 14 | IP LBCRAC True-up Revenue ($000) | | | | | | | | | | | | | | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 751 | 863 | 770 | 770 | 870 | 940 | 788 | 1,003 | 808 | 959 | 978 | 796 | 10,296 | | |
| 17 | HLH Energy (MWhr) | 171,719 | 239,003 | 224,011 | 217,419 | 187,526 | 143,338 | 108,238 | 180,235 | 96,442 | 134,718 | 158,477 | 79,495 | 1,940,621 | 222 | 1,941 |
| 18 | LLH Energy (MWhr) | -129,870 | -42,585 | -78,946 | -90,293 | -74,210 | -146,665 | -44,319 | 9,357 | -19,103 | 21,631 | -5,171 | -92,823 | -692,997 | -79 | -693 |
| 19 | Energy (aMW) | 56 | 272 | 195 | 171 | 169 | -4 | 89 | 255 | 107 | 210 | 206 | -19 | 1,707 | 142 | 1,248 |
| 20 | Revenue ($ Thousand) | $3,951 | $10,923 | $10,768 | $10,811 | $10,175 | $7,503 | $7,331 | $7,536 | $4,027 | $6,514 | $7,981 | $3,980 | $91,498 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,273 | 1,273 | 14,996 | | |
| 24 | HLH Energy (MWhr) | 346,350 | 334,728 | 345,886 | 345,886 | 312,413 | 345,886 | 334,263 | 345,886 | 334,728 | 345,886 | 421,922 | 408,312 | 4,222,146 | 482 | 4,222 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 567 | 567 | 5,783 | 482 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | 357,945 | 445,952 | 403,914 | 829,746 | 136,700 | 796,138 | 502,329 | 613,200 | 616,800 | 72,800 | 41,600 | 40,000 | 4,857,124 | 554 | 4,857 |
| 30 | Monthly Trading Floor Committed Sales ($000) | $19,669 | $21,826 | $22,239 | $33,118 | $4,668 | $22,333 | $18,584 | $24,159 | $24,990 | $4,878 | $2,174 | $2,090 | $200,727 | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | | | | | | | 791,866 | 1,347,854 | 1,885,286 | 1,060,593 | 47,628 | 205,501 | 5,338,728 | 609 | 5,339 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | | | | | | | $20,412 | $28,616 | $40,960 | $29,549 | $1,449 | $6,029 | $127,015 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | -98,215 | -122,762 | -143,872 | -1,904 | -29,136 | -121,373 | | | | | | | -517,262 | -59 | -517 |
| 36 | Revenue reversals ($000) | -$5,185 | -$5,930 | -$8,411 | $0 | -$1,083 | -$3,450 | | | | | | | -$24,059 | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $261 | $299 | $337 | $272 | $269 | $238 | $206 | $221 | $215 | $260 | $291 | $264 | $3,134 | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | Renewable HLH (MWH) | 34,311 | 34,324 | 41,382 | 47,002 | 21,638 | 38,693 | 28,678 | 26,230 | 27,059 | 28,177 | 24,661 | 24,297 | 376,451 | 43 | 376 |
| 43 | Renewable LLH (MWH) | 6,519 | 6,070 | 9,789 | 9,829 | 8,209 | 28,514 | 23,689 | 24,297 | 26,321 | 25,352 | 22,458 | 19,996 | 211,044 | 24 | 211 |
| 44 | Renewable Expense ($000) (included in Program Expense Forecast) | $2,017 | $2,071 | $2,587 | $2,933 | $1,681 | $3,394 | $2,694 | $2,669 | $2,727 | $2,744 | $2,437 | $2,317 | $30,273 | | |
| 45 | | | | | | | | | | | | | | | | |
| 46 | Power Purchases Bookouts (MWH) | -98,215 | -122,762 | -143,872 | -1,904 | -29,136 | -121,373 | 0 | 0 | 0 | 0 | 0 | 0 | -517,262 | -59 | -517 |
| 47 | Power Purchases Reversals ($000) | -$5,185 | -$5,930 | -$8,411 | $0 | -$1,083 | -$3,450 | $0 | $0 | $0 | $0 | $0 | $0 | -$24,059 | | |
| 48 | | | | | | | | | | | | | | | | |
| 49 | Augmentation Power Purchases (MWH) | | | | | | | | | | | | | 0 | 0 | 0 |
| 50 | Augmentation Power Purchases ($000) | | | | | | | | | | | | | $0 | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | Other Committed Power Purchases (MWH) | 5,669 | 6,860 | 3,092 | 1,773 | 9,682 | 9,801 | 15,033 | 24,268 | 44,612 | 27,856 | 15,507 | 5,796 | 169,950 | 19 | 170 |
| 53 | Balancing Power Purchases (MWH) | | | | | | | 420 | 17,608 | - | 10,895 | 435,023 | 207,637 | 671,584 | 77 | 672 |
| 54 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | 502,816 | 612,716 | 937,212 | 138,711 | 642,173 | 626,970 | 118,824 | - | - | 131,200 | 291,000 | 168,000 | 4,169,622 | 476 | 4,170 |
| 55 | Other Committed Purchase Power Expense ($000) | **$660** | **$564** | **$793** | **$687** | **$390** | **$726** | **$952** | **$991** | **$1,118** | **$1,640** | **$330** | **$513** | **$9,365** | | |
| 56 | Balancing Purchase Power Expense ($000) | | | | | | | $11 | $451 | $0 | $319 | $14,700 | $6,656 | **$22,136** | | |
| 57 | Trading Floor Purchase Power Expense ($000) | **$24,625** | **$30,061** | **$61,783** | **$4,924** | **$26,086** | **$18,938** | **$3,245** | **$0** | **$0** | **$3,850** | **$10,646** | **$5,636** | **$189,793** | | |
| 58 | | | | | | | | | | | | | | | | |
| 59 | Lookback adjustment | $4,665 | $5,750 | $7,102 | $7,986 | $6,592 | $6,178 | $5,357 | $4,969 | $5,019 | $6,075 | $5,774 | $5,303 | $70,768 | | |
| 60 | Residential Exchange Power Purchase | 2,357,543 | 2,669,837 | 3,476,522 | 4,317,495 | 3,368,129 | 3,127,975 | 2,701,817 | 2,484,845 | 2,481,228 | 2,644,717 | 2,528,174 | 2,314,738 | 34,473,020 | 3,935 | 34,473 |
| 61 | Residential Exchange cost | $129,830 | $147,028 | $191,452 | $237,764 | $185,483 | $172,258 | $148,789 | $136,840 | $136,641 | $145,645 | $139,227 | $127,473 | $1,898,429 | | |

## TABLE 4.6.1 REVENUE AT CURRENT RATES

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2010** | | | | | | | | | | | | |
| 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | | |
| 10 | Energy (MWhr) | 2,649,207 | 2,942,305 | 3,728,537 | 4,324,412 | 4,007,690 | 3,704,316 | 3,386,118 | 2,215,354 | 1,840,532 | 1,833,428 | 2,299,252 | 2,861,130 | 35,792,280 | | |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$126,298 | -$140,271 | -$177,753 | -$206,161 | -$191,062 | -$176,599 | -$161,429 | -$105,614 | -$87,745 | -$87,406 | -$109,614 | -$136,401 | -$1,706,352 | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | 299,088 | 289,842 | 299,088 | 299,088 | 270,144 | 298,686 | 289,440 | 299,088 | 289,440 | 299,088 | 299,088 | 289,440 | 3,521,520 | 402 | 3,522 |
| 14 | IP LBCRAC True-up Revenue ($000) | $11,671 | $11,908 | $12,927 | $10,920 | $10,142 | $10,382 | $9,450 | $7,928 | $6,548 | $9,077 | $10,679 | $10,986 | $122,619 | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 851 | 963 | 870 | 870 | 870 | 788 | 788 | 988 | 770 | 785 | 938 | 758 | 10,239 | | |
| 17 | HLH Energy (MWhr) | 54,962 | 98,624 | 142,515 | 159,523 | 125,172 | 94,802 | 100,158 | 178,576 | 89,776 | 67,322 | 145,400 | 74,435 | 1,331,265 | 152 | 1,331 |
| 18 | LLH Energy (MWhr) | -129,189 | -50,621 | -16,121 | -34,115 | -13,973 | -47,213 | -40,587 | 9,357 | -47,376 | -38,354 | -3,129 | -87,730 | -499,051 | -57 | -499 |
| 19 | Energy (aMW) | -100 | 67 | 170 | 169 | 165 | 64 | 83 | 253 | 59 | 39 | 191 | -18 | 1,141 | 95 | 832 |
| 20 | Revenue ($ Thousand) | $3,982 | $10,285 | $10,455 | $10,444 | $9,903 | $7,266 | $7,165 | $7,536 | $4,027 | $4,023 | $6,629 | $3,980 | $85,694 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,240 | 1,240 | 15,210 | | |
| 24 | HLH Energy (MWhr) | 422,490 | 408,312 | 421,922 | 421,922 | 381,091 | 421,922 | 407,745 | 421,922 | 408,312 | 421,922 | 392,088 | 379,440 | 4,909,088 | 560 | 4,909 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 527 | 527 | 6,725 | 560 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | | | | | | | | | | | | | | | |
| 30 | Monthly Trading Floor Committed Sales ($000) | | | | | | | | | | | | | | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | 264,582 | 441,458 | 619,865 | 1,297,484 | 1,051,699 | 1,335,168 | 1,823,398 | 3,066,531 | 2,349,974 | 1,750,318 | 566,422 | 272,940 | 14,839,839 | 1,694 | 14,840 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | $8,514 | $15,446 | $23,222 | $55,912 | $42,798 | $52,434 | $63,709 | $102,412 | $78,428 | $66,440 | $24,115 | $11,201 | $544,632 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | | | | | | | | | | | | | | | |
| 36 | Revenue reversals ($000) | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $215 | $233 | $271 | $216 | $202 | $185 | $147 | $184 | $197 | $211 | $256 | $204 | $2,522 | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | 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 |
| 43 | 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 |
| 44 | Renewable Expense ($000) (included in Program Expense Forecast) | $2,431 | $2,444 | $2,371 | $2,250 | $2,149 | $3,453 | $2,750 | $2,869 | $2,760 | $2,764 | $2,435 | $2,318 | $30,994 | | |
| 45 | | | | | | | | | | | | | | | | |
| 46 | Power Purchases Bookouts (MWH) | | | | | | | | | | | | | | | |
| 47 | Power Purchases Reversals ($000) | | | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | | | | |
| 49 | Augmentation Power Purchases (MWH) | 353,933 | 342,992 | 353,933 | 353,933 | 319,681 | 353,457 | 342,516 | 353,933 | 342,516 | 353,933 | 353,933 | 342,516 | 4,167,276 | 476 | 4,167 |
| 50 | Augmentation Power Purchases ($000) | $15,126 | $14,659 | $15,126 | $15,126 | $13,662 | $15,106 | $14,638 | $15,126 | $14,638 | $15,126 | $15,126 | $14,638 | $178,100 | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | 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 |
| 53 | Balancing Power Purchases (MWH) | 67,363 | 242,691 | 276,916 | 331,699 | 250,469 | 151,184 | 151,073 | 2,469 | 7,222 | 23,487 | 131,834 | 71,560 | 1,707,967 | 195 | 1,708 |
| 54 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | | | | | | | | | | | | | | | |
| 55 | Other Committed Purchase Power Expense ($000) | $384 | $390 | $370 | $439 | $473 | $145 | $124 | $175 | $162 | $117 | $167 | $118 | $3,065 | | |
| 56 | Balancing Purchase Power Expense ($000) | $2,038 | $11,378 | $13,579 | $16,913 | $13,112 | $8,763 | $8,621 | $85 | $301 | $899 | $5,785 | $3,091 | $84,566 | | |
| 57 | Trading Floor Purchase Power Expense ($000) | | | | | | | | | | | | | | | |
| 58 | | | | | | | | | | | | | | | | |
| 59 | Lookback adjustment | | | | | | | | | | | | | | | |
| 60 | Residential Exchange Power Purchase | 2,649,207 | 2,942,305 | 3,728,537 | 4,324,412 | 4,007,690 | 3,704,316 | 3,386,118 | 2,215,354 | 1,840,532 | 1,833,428 | 2,299,252 | 2,861,130 | 35,792,280 | 4,086 | 35,792 |
| 61 | Residential Exchange cost | $144,090 | $160,032 | $202,795 | $235,205 | $217,978 | $201,478 | $184,171 | $120,493 | $100,107 | $99,720 | $125,056 | $155,617 | $1,946,742 | | |

# TABLE 4.6.1 REVENUE AT CURRENT RATES

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2011** | | | | | | | | | | | | |
| 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | (47.56) | | |
| 10 | Energy (MWhr) | 2,601,476 | 2,958,308 | 3,739,296 | 4,324,875 | 4,004,777 | 3,683,861 | 3,309,864 | 2,372,017 | 1,934,557 | 1,919,477 | 2,397,118 | 2,950,443 | 36,196,069 | | |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$123,728 | -$140,700 | -$177,844 | -$205,695 | -$190,470 | -$175,207 | -$157,420 | -$112,815 | -$92,009 | -$91,292 | -$114,009 | -$140,325 | ($1,721,514) | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | 299,088 | 289,842 | 299,088 | 299,088 | 270,144 | 298,686 | 289,440 | 299,088 | 289,440 | 299,088 | 299,088 | 289,440 | 3,521,520 | 402 | 3,522 |
| 14 | IP LBCRAC True-up Revenue ($000) | 11,671 | 11,908 | 12,927 | 10,920 | 10,142 | 10,382 | 9,450 | 7,928 | 6,548 | 9,077 | 10,679 | 10,986 | $122,619 | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 828 | 947 | 854 | 854 | 854 | 772 | 772 | 965 | 770 | 800 | 784 | 183 | 9,383 | | |
| 17 | HLH Energy (MWhr) | 49,873 | 97,242 | 139,155 | 155,843 | 121,972 | 91,281 | 96,708 | 173,826 | 89,776 | 67,498 | 78,083 | -6,696 | 1,154,561 | 132 | 1,155 |
| 18 | LLH Energy (MWhr) | -119,795 | -44,396 | -7,954 | -26,149 | -7,244 | -39,709 | -35,127 | 13,899 | -47,376 | -38,596 | -61,515 | -6,599 | -420,561 | -48 | -421 |
| 19 | Energy (aMW) | -94 | 73 | 176 | 174 | 171 | 69 | 86 | 252 | 59 | 39 | 22 | -18 | 1,010 | 84 | 734 |
| 20 | Revenue ($ Thousand) | $3,982 | $10,146 | $10,316 | $10,305 | $9,764 | $7,127 | $7,026 | $7,336 | $4,027 | $4,024 | $4,372 | $59 | $78,483 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 14,880 | | |
| 24 | HLH Energy (MWhr) | 392,615 | 379,440 | 392,088 | 392,088 | 354,144 | 392,088 | 378,913 | 392,088 | 379,440 | 392,088 | 384,648 | 372,240 | 4,601,880 | 525 | 4,602 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 6,288 | 525 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | | | | | | | | | | | | | | | |
| 30 | Monthly Trading Floor Committed Sales ($000) | | | | | | | | | | | | | | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | 533,732 | 499,896 | 706,318 | 1,486,068 | 1,142,705 | 1,506,518 | 1,671,295 | 2,727,700 | 2,172,688 | 1,810,013 | 727,604 | 355,182 | 15,339,720 | 1,751 | 15,340 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | $22,235 | $21,049 | $30,042 | $64,900 | $48,333 | $61,709 | $60,252 | $93,306 | $73,618 | $71,649 | $31,736 | $15,114 | $593,944 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | | | | | | | | | | | | | | | |
| 36 | Revenue reversals ($000) | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $166 | $180 | $208 | $166 | $156 | $142 | $114 | $131 | $134 | $159 | $197 | $157 | $1,909 | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | 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 |
| 43 | 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 |
| 44 | Renewable Expense ($000) (included in Program Expense Forecast) | $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 | | |
| 45 | | | | | | | | | | | | | | | | |
| 46 | Power Purchases Bookouts (MWH) | | | | | | | | | | | | | | | |
| 47 | Power Purchases Reversals ($000) | | | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | | | | |
| 49 | Augmentation Power Purchases (MWH) | 506,186 | 490,537 | 506,186 | 506,186 | 457,200 | 505,505 | 489,857 | 506,186 | 489,857 | 506,186 | 506,186 | 489,857 | 5,959,928 | 680 | 5,960 |
| 50 | Augmentation Power Purchases ($000) | $23,020 | $22,309 | $23,020 | $23,020 | $20,793 | $22,989 | $22,278 | $23,020 | $22,278 | $23,020 | $23,020 | $22,278 | $271,045 | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | 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 |
| 53 | Balancing Power Purchases (MWH) | 4,402 | 156,897 | 208,567 | 283,867 | 214,360 | 131,400 | 175,784 | 16,417 | 25,379 | 4,283 | 51,699 | 34,874 | 1,307,928 | 149 | 1,308 |
| 54 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | | | | | | | | | | | | | | | |
| 55 | Other Committed Purchase Power Expense ($000) | $54 | $60 | $40 | $109 | $143 | $145 | $124 | $175 | $162 | $117 | $167 | $118 | $1,415 | | |
| 56 | Balancing Purchase Power Expense ($000) | $198 | $8,811 | $11,273 | $15,047 | $11,674 | $7,919 | $9,710 | $642 | $1,107 | $173 | $2,588 | $1,548 | $70,692 | | |
| 57 | Trading Floor Purchase Power Expense ($000) | | | | | | | | | | | | | | | |
| 58 | | | | | | | | | | | | | | | | |
| 59 | Lookback adjustment | | | | | | | | | | | | | | | |
| 60 | Residential Exchange Power Purchase | 2,601,476 | 2,958,308 | 3,739,296 | 4,324,875 | 4,004,777 | 3,683,861 | 3,309,864 | 2,372,017 | 1,934,557 | 1,919,477 | 2,397,118 | 2,950,443 | 36,196,069 | 4,132 | 36,196 |
| 61 | Residential Exchange cost | $146,905 | $167,056 | $211,158 | $244,226 | $226,150 | $208,028 | $186,908 | $133,948 | $109,244 | $108,393 | $135,365 | $166,612 | $2,043,992 | | |

# TABLE 4.6.1 REVENUE AT CURRENT RATES

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2009** | | | | | | | | | | | | |
| 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $8 | $165 | $129 | $0 | $0 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $1,178 | | |
| 10 | Energy Imbalance | $452 | $683 | $790 | $650 | $265 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,840 | | |
| 11 | Federal RAS for Generation Dropping | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $396 | | |
| 12 | Synchronous Condensing | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $4,091 | 0 | 0 |
| 13 | Station Service | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $2,089 | 24 | 212750 |
| 14 | Regulating Reserves | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $13,158 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $2,395 | $2,254 | $2,624 | $2,786 | $2,442 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $31,694 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $7,397 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $738 | $738 | $738 | $840 | $911 | $1,028 | $1,201 | $1,201 | $1,492 | $1,492 | $2,120 | $2,120 | $14,617 | | |
| 18 | **Total Interbusiness Line** | **$5,854** | **$6,101** | **$6,542** | **$6,538** | **$5,878** | **$6,156** | **$6,329** | **$6,329** | **$6,619** | **$6,619** | **$7,247** | **$7,247** | **$77,460** | 24 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $158 | $198 | $359 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $3,438 | | |
| 22 | **Total Reserve Services** | **$158** | **$198** | **$359** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$3,438** | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$6,012** | **$6,300** | **$6,901** | **$6,840** | **$6,181** | **$6,459** | **$6,631** | **$6,631** | **$6,922** | **$6,922** | **$7,550** | **$7,550** | **$80,897** | 24 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $882 | $848 | $864 | $858 | $845 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $9,646 | | |
| 29 | Slice True-Up (and Implementation costs) | | | | | | | | | | | | $5,370 | $5,370 | | |
| 30 | Misc. Generation | $288 | $328 | $395 | $614 | $308 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,927 | | |
| 31 | Energy Efficiency Rev's | $2,431 | $639 | $1,111 | $931 | $780 | $605 | $801 | $901 | $1,000 | $1,000 | $1,500 | $2,800 | $14,500 | | |
| 32 | Green Tags and Green Premiums Bulk | $56 | $162 | $325 | $5 | $198 | $90 | $90 | $90 | $90 | $90 | $90 | $147 | $1,434 | | |
| 33 | Green Premium West | $150 | $145 | $147 | $147 | $133 | $24 | $23 | $24 | $23 | $24 | $24 | $23 | $886 | | |
| 34 | Green Premium East | $111 | $108 | $111 | $111 | $100 | $113 | $110 | $113 | $110 | $113 | $113 | $110 | $1,323 | | |
| 35 | 4(h)(10)c credit | $7,547 | $6,954 | $7,088 | $7,029 | $7,894 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $78,578 | | |
| 36 | Network Wind Integration&Shaping | $170 | $170 | $170 | $170 | $170 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,989 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$12,018** | **$9,737** | **$10,594** | **$10,249** | **$10,813** | **$8,387** | **$8,598** | **$8,731** | **$8,845** | **$8,868** | **$9,360** | **$16,055** | **$122,254** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$5,849** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$5,804** | **$5,804** | **$5,804** | **$5,641** | **$5,641** | **$70,564** | | |
| 43 | **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 REVENUE AT CURRENT RATES

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | | Revenues at Current Rates | | | | | | | | | | | | |
| 2 | | | | Revenue ($ Thousands) | | | | | | | | | | | | |
| 3 | | | | **FY2010** | | | | | | | | | | | | |
| 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $1,500 | | |
| 10 | Energy Imbalance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 11 | Federal RAS for Generation Dropping | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $396 | | |
| 12 | Synchronous Condensing | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $1,466 | 0 | 0 |
| 13 | Station Service | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $1,891 | 14 | 1E+05 |
| 14 | Regulating Reserves | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $7,281 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $26,551 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $7,397 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $55,107 | | |
| 18 | **Total Interbusiness Line** | **$8,341** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$101,590** | 14 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 22 | **Total Reserve Services** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$8,341** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$101,590** | 14 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $731 | $710 | $710 | $710 | $711 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $8,921 | | |
| 29 | Slice True-Up (and Implementation costs) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($5,282) | ($5,282) | | |
| 30 | Misc. Generation | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,420 | | |
| 31 | 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 | | |
| 32 | Green Tags and Green Premiums Bulk | $404 | $378 | $357 | $320 | $296 | $589 | $446 | $489 | $467 | $477 | $423 | $394 | $5,040 | | |
| 33 | Green Premium West | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 34 | Green Premium East | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 35 | 4(h)(10)c credit | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $96,689 | | |
| 36 | Network Wind Integration&Shaping | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,953 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$11,390** | **$11,343** | **$11,323** | **$11,286** | **$11,262** | **$11,558** | **$11,435** | **$11,506** | **$11,504** | **$12,899** | **$12,837** | **$7,498** | **$135,842** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$89,018** | | |
| 43 | **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 REVENUE AT CURRENT RATES

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:20 | | Revenues at Current Rates | | | | | | | | | | | | | |
| 2 | | | Revenue ($ Thousands) | | | | | | | | | | | | | |
| 3 | | | FY2011 | | | | | | | | | | | | | |
| 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $1,500 | | |
| 10 | Energy Imbalance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 11 | Federal RAS for Generation Dropping | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $396 | | |
| 12 | Synchronous Condensing | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $122 | $1,466 | 0 | 0 |
| 13 | Station Service | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $158 | $1,891 | 14 | ###### |
| 14 | Regulating Reserves | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $607 | $7,281 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $2,213 | $26,551 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $7,397 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $4,592 | $55,107 | | |
| 18 | **Total Interbusiness Line** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$101,590** | 14 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 22 | **Total Reserve Services** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$8,466** | **$101,590** | 14 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $731 | $710 | $710 | $710 | $711 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $8,921 | | |
| 29 | Slice True-Up (and Implementation costs) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $10,942 | $10,942 | | |
| 30 | Misc. Generation | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,420 | | |
| 31 | 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 | | |
| 32 | Green Tags and Green Premiums Bulk | $404 | $378 | $357 | $320 | $296 | $589 | $446 | $489 | $467 | $477 | $423 | $394 | $5,040 | | |
| 33 | Green Premium West | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 34 | Green Premium East | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 35 | 4(h)(10)c credit | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $101,969 | | |
| 36 | Network Wind Integration&Shaping | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,953 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$11,830** | **$11,783** | **$11,763** | **$11,726** | **$11,702** | **$11,998** | **$11,875** | **$11,946** | **$11,944** | **$13,339** | **$13,277** | **$24,162** | **$157,345** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$88,352** | | |
| 43 | **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 | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | **FY 2009** | | **FY 2010** | | **FY 2011** | |
| 3 | | **($000)** | **aMW** | **($000)** | **aMW** | **($000)** | **aMW** |
| 4 | **Revenues** | | | | | | |
| 5 | **PF Preference** | $1,228,242 | 5,299 | $1,302,923 | 5,211 | $1,321,640 | 5,284 |
| 6 | **Lookback Adjustment** | ($70,769) | 0 | $0 | 0 | $0 | 0 |
| 7 | **PF Slice** | $502,645 | 1,680 | $528,120 | 2,082 | $528,264 | 2,067 |
| 8 | **Pre-sub/Hungry Horse** | $37,624 | 210 | $37,235 | 199 | $34,462 | 201 |
| 9 | **Irrigation Mitigation** | $20,212 | 196 | $22,022 | 191 | $21,953 | 190 |
| 10 | **Industrial Power** | $0 | 0 | $121,852 | 403 | $121,852 | 403 |
| 11 | **Long-Term Obligations** | $91,498 | 624 | $96,778 | 655 | $88,437 | 609 |
| 12 | **Generation Inputs/Reserve Services** | $80,897 | 24 | $90,171 | 14 | $102,735 | 14 |
| 13 | **Slice True-Up** | $5,370 | 0 | ($5,282) | 0 | $10,942 | 0 |
| 14 | **Network Wind Integration & Shaping** | $1,989 | 0 | $1,953 | 0 | $1,953 | 0 |
| 15 | **4h10C credits** | $78,578 | 0 | $96,689 | 0 | $101,969 | 0 |
| 16 | **Colville credits** | $4,600 | 0 | $4,600 | 0 | $4,600 | 0 |
| 17 | **Downstream Benefits/Storage** | $9,646 | 175 | $8,921 | 175 | $8,921 | 175 |
| 18 | **Energy Efficiency** | $14,500 | 0 | $20,500 | 0 | $20,500 | 0 |
| 19 | **Green Tags/Green Premiums** | $3,644 | 0 | $5,040 | 0 | $5,040 | 0 |
| 20 | **Misc Generation** | $3,927 | 0 | $3,420 | 0 | $3,420 | 0 |
| 21 | **Secondary Sales** | $327,742 | 1,164 | $544,632 | 1,694 | $593,944 | 1,751 |
| 22 | **Bookouts** | ($24,059) | -59 | $0 | 0 | $0 | 0 |
| 23 | **Ad hoc Gen Input adjustment** | | | | | | |
| 24 | **Total Revenue** | $2,316,286 | 9,312 | $2,879,575 | 10,624 | $2,970,633 | 10,694 |
| 25 | **Purchases** | | | | | | |
| 26 | **Augmentation Purchases** | $3,134 | 13 | $180,766 | 486 | $273,043 | 688 |
| 27 | **Secondary Purchases** | $211,930 | 553 | $84,566 | 195 | $70,692 | 149 |

## TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 22, 2009 @ 15:58 | | | | | | Revenues at Proposed Rates | | | | | | | | | |
| 2 | | | | | | | | Revenue ($ Thousands) | | | | | | | | | |
| 3 | | | | | | | | **Fiscal Year 2009** | | | | | | | | | |
| 4 | | | | | | | | | | | | | | | | | |
| 5 | | | $26.81 | $2.03 | | | | | | | | | | | | | |
| 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 | | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | | | | | | | | | | | | | | | |
| 10 | | LLH Energy Flat | 275,595 | 328,586 | 414,396 | 401,655 | 336,365 | 326,384 | 301,624 | 289,916 | 252,472 | 266,250 | 254,797 | 263,424 | 3,711,464 | 424 | 3711 |
| 11 | | HLH Energy Flat | 461,962 | 452,386 | 622,642 | 597,386 | 521,181 | 525,558 | 477,297 | 430,813 | 420,450 | 411,867 | 430,484 | 409,319 | 5,761,345 | 658 | 5761 |
| 12 | | 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 | | | |
| 13 | | 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 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $5,343 | $7,465 | $9,883 | $8,017 | $6,781 | $6,257 | $5,318 | $4,108 | $2,487 | $4,454 | $5,058 | $5,840 | $71,012 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $12,694 | $14,092 | $20,242 | $16,488 | $14,692 | $13,743 | $11,713 | $8,832 | $7,799 | $9,411 | $11,520 | $11,305 | $152,532 | | |
| 16 | | Demand | 1,398 | 1,214 | 1,881 | 1,596 | 1,703 | 1,568 | 1,396 | 1,088 | 1,045 | 1,074 | 1,040 | 1,027 | 16,030 | | |
| 17 | | 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 | | | |
| 18 | | Demand Revenue = 17*18 | $2,563 | $2,477 | $4,026 | $2,904 | $3,151 | $2,697 | $2,262 | $1,458 | $1,285 | $1,611 | $1,830 | $1,869 | $28,134 | | |
| 19 | | Load Variance | 750,216 | 793,646 | 1,051,953 | 1,013,764 | 869,157 | 909,632 | 836,154 | 782,813 | 732,274 | 737,461 | 743,680 | 725,315 | 9,946,064 | 1135 | 9946 |
| 20 | | 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 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $315 | $365 | $484 | $466 | $400 | $418 | $385 | $360 | $337 | $339 | $342 | $334 | $4,545 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -1.66% | -1.84% | -1.95% | -1.95% | -1.94% | -2.38% | -2.38% | -2.44% | -2.40% | -2.28% | -2.26% | -2.26% | | | |
| 23 | | Low Density Discount | -$348 | -$449 | -$675 | -$543 | -$486 | -$550 | -$468 | -$360 | -$286 | -$361 | -$425 | -$438 | -$5,388 | | |
| 24 | -1,008,619 | 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 | | |
| 25 | | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | | | |
| 26 | | PF Other revenues | $4 | $0 | $0 | $0 | $0 | | | | | | | | $4 | | |
| 27 | | | | | | | | | | | | | | | | | |
| 28 | | **PF Partial Service** | | | | | | | | | | | | | | | |
| 29 | | LLH Energy Flat | 312,148 | 347,212 | 412,690 | 398,298 | 338,926 | 327,080 | 297,780 | 356,279 | 267,650 | 290,224 | 290,497 | 291,308 | 3,930,093 | 449 | 3,930 |
| 30 | | HLH Energy Flat | 497,690 | 443,562 | 576,742 | 559,797 | 493,919 | 579,795 | 555,036 | 568,611 | 490,382 | 521,350 | 542,248 | 517,406 | 6,346,539 | 724 | 6,347 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $6,681 | $7,889 | $9,843 | $7,950 | $6,833 | $6,270 | $5,250 | $5,048 | $2,636 | $4,855 | $5,766 | $6,458 | $75,480 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $14,535 | $13,817 | $18,750 | $15,450 | $13,924 | $15,162 | $13,621 | $11,657 | $9,097 | $11,913 | $14,511 | $14,291 | $166,726 | | |
| 33 | | GSP Demand | 1,454 | 1,321 | 1,951 | 1,672 | 1,676 | 1,468 | 1,425 | 1,359 | 1,168 | 1,252 | 1,262 | 1,265 | 17,273 | | |
| 34 | | Demand Revenue (34*18) | $2,777 | $2,695 | $4,175 | $3,043 | $3,100 | $2,525 | $2,308 | $1,822 | $1,437 | $1,878 | $2,221 | $2,303 | $30,283 | | |
| 35 | | Load Variance | 1,038,945 | 1,019,974 | 1,238,664 | 1,211,281 | 1,063,890 | 1,144,954 | 1,087,995 | 1,052,352 | 1,007,251 | 1,042,228 | 1,053,565 | 1,021,789 | 12,982,888 | 1482 | 12983 |
| 36 | | Load Variance Revenue (36*21)/1000 | $478 | $469 | $570 | $557 | $489 | $527 | $500 | $484 | $463 | $479 | $485 | $470 | $5,972 | | |
| 37 | -1,133,980 | 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 | | |
| 38 | | PF Other Energy | 0 | 0 | 0 | 0 | 1 | | | | | | | | | | |
| 39 | | PF Other revenues | $0 | $23 | $0 | $0 | $0 | | | | | | | | $23 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | | | | | | | | | | | | | | | |
| 42 | | LLH Energy Flat | 392,808 | 521,676 | 578,264 | 588,104 | 510,624 | 562,702 | 403,016 | 363,494 | 291,791 | 357,555 | 390,748 | 447,947 | 5,408,729 | 617 | 5,409 |
| 43 | | HLH Energy Flat | 562,464 | 647,424 | 786,656 | 790,816 | 713,856 | 715,854 | 551,495 | 410,513 | 388,255 | 437,536 | 481,595 | 559,934 | 7,046,398 | 804 | 7,046 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $8,406 | $11,852 | $13,792 | $11,739 | $10,294 | $10,787 | $7,105 | $5,151 | $2,874 | $5,982 | $7,756 | $9,931 | $105,669 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $16,430 | $20,167 | $25,574 | $21,827 | $20,124 | $18,720 | $13,534 | $8,416 | $7,202 | $9,998 | $12,887 | $15,465 | $190,343 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,408 | 1,812 | 2,006 | 2,059 | 1,992 | 1,721 | 1,326 | 1,137 | 1,088 | 1,225 | 1,308 | 1,400 | 18,482 | | |
| 49 | | Demand Revenue (49*24) | $2,689 | $3,696 | $4,293 | $3,747 | $3,685 | $2,960 | $2,148 | $1,523 | $1,338 | $1,838 | $2,303 | $2,548 | $32,769 | | |
| 50 | -1,309,822 | 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 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.89% | -0.79% | -0.80% | -0.81% | -0.79% | -0.75% | -1.00% | -0.94% | -0.87% | -0.78% | -0.71% | -0.95% | | | |
| 53 | | Low-Density Discount | -$246 | -$282 | -$351 | -$304 | -$271 | -$244 | -$228 | -$143 | -$99 | -$140 | -$162 | -$266 | -$2,735 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | $0 | | |
| 56 | | | | | | | | | | | | | | | | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,975 | 39,179 | 0 | 152,052 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,493 | 65,398 | 73,313 | 64,136 | 0 | 248,340 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $710 | $721 | $1,383 | $1,568 | $0 | $4,382 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | 5,124 | 5,972 | 3,984 | 5,629 | 5,721 | 5,559 | 5,168 | 5,848 | 5,168 | 5,576 | 5,576 | 5,440 | 64,765 | 7 | 65 |
| 62 | | **Pt Townsend HLH** | 6,871 | 6,774 | 5,551 | 7,230 | 7,429 | 7,072 | 7,072 | 6,800 | 7,072 | 7,072 | 7,072 | 6,800 | 82,815 | 9 | 83 |
| 63 | | **Pt Townsend Demand** | 18 | 19 | 19 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 17 | 210 | | |
| 64 | | **Pt Townsend Revenues** | $359 | $401 | $328 | $357 | $371 | $328 | $299 | $252 | $210 | $288 | $337 | $346 | $3,876 | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF Slice | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.51% | 1331 | |
| 68 | | 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 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $34,660 | $34,660 | $34,660 | $34,660 | $34,660 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $34,663 | $415,936 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | 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 | | |
| 72 | | LDD Percentage | -1.08% | -1.08% | -1.08% | -1.08% | -1.08% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | -1.12% | | | |
| 73 | | Low-Density Discount | -373 | -373 | -373 | -373 | -373 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$4,588 | | |
| 74 | | Slice Other | $0 | $0 | -$1,033 | $52 | $0 | | | | | | | | -$981 | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,248 | 1,348 | 1,312 | 1,312 | 1,152 | 6,867 | 6,384 | 7,224 | 6,384 | 6,888 | 6,888 | 6,720 | 53,727 | 6 | 54 |
| 77 | | LLH Energy Revenue | $25 | $27 | $26 | $26 | $23 | $27 | $25 | $29 | $25 | $27 | $27 | $27 | $313 | | |
| 78 | | HLH Energy Full Service | 1,728 | 1,536 | 1,664 | 1,664 | 1,536 | 8,736 | 8,736 | 8,400 | 8,736 | 8,736 | 8,736 | 8,400 | 68,608 | 8 | 69 |
| 79 | | HLH Energy Revenue | $34 | $30 | $33 | $33 | $30 | $35 | $35 | $33 | $35 | $35 | $35 | $33 | $400 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 167 | | |
| 81 | | Demand Revenue | -$4 | -$4 | -$4 | -$4 | -$4 | | | | | | | | -$20 | | |
| 82 | | Load Variance | 0 | 0 | 0 | 0 | 0 | 15,603 | 15,120 | 15,624 | 15,120 | 15,624 | 15,624 | 15,120 | 107,835 | 12 | 108 |
| 83 | | Load Variance Revenue | $0 | $0 | $0 | $0 | $0 | $7 | $7 | $7 | $7 | $7 | $7 | $7 | $50 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | $10 | $10 | $14 | $13 | $10 | | | | | | | | $57 | | |
| 88 | | **Total** | $102,489 | $114,484 | $140,744 | $121,509 | $112,891 | $109,398 | $93,542 | $79,115 | $67,298 | $83,727 | $95,796 | $100,253 | $1,263,670 | | |

**TABLE 4.6.2 REVENUE AT PROPOSED RATES**

| | A | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 22, 2009 @ 15:58 | | | | | | 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 | | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | | | | | | | | | | | | | | | |
| 10 | | LLH Energy Flat | 275,385 | 349,641 | 387,390 | 385,617 | 328,467 | 312,183 | 291,681 | 277,240 | 243,958 | 270,676 | 249,430 | 259,424 | 3,631,092 | 415 | 3631 |
| 11 | | HLH Energy Flat | 458,093 | 523,708 | 582,651 | 581,666 | 525,031 | 508,570 | 464,840 | 417,011 | 407,021 | 389,772 | 420,595 | 403,621 | 5,682,579 | 649 | 5683 |
| 12 | | PF Flat LLH Energy Rate | $23.01 | $24.43 | $25.65 | $21.46 | $21.68 | $20.61 | $18.97 | $15.24 | $10.59 | $17.99 | $21.34 | $23.84 | | | |
| 13 | | PF Flat HLH Energy Rate | $31.41 | $33.49 | $34.96 | $29.68 | $30.31 | $28.12 | $26.39 | $22.04 | $19.95 | $24.57 | $28.77 | $29.70 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $6,337 | $8,542 | $9,937 | $8,275 | $7,121 | $6,434 | $5,533 | $4,225 | $2,584 | $4,869 | $5,323 | $6,185 | $75,364 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $14,389 | $17,539 | $20,369 | $17,264 | $15,914 | $14,301 | $12,267 | $9,191 | $8,120 | $9,577 | $12,101 | $11,988 | $163,019 | | |
| 16 | | Demand | 1,457 | 1,574 | 1,697 | 1,772 | 1,716 | 1,549 | 1,381 | 1,067 | 1,041 | 1,079 | 1,026 | 1,019 | 16,378 | | |
| 17 | | PF GSP Demand Rate | $2.05 | $2.19 | $2.30 | $1.96 | $1.99 | $1.85 | $1.74 | $1.44 | $1.32 | $1.61 | $1.89 | $1.96 | | | |
| 18 | | Demand Revenue = 17*18 | $2,986 | $3,446 | $3,902 | $3,473 | $3,414 | $2,866 | $2,403 | $1,537 | $1,374 | $1,736 | $1,940 | $1,998 | $31,076 | | |
| 19 | | Load Variance | 754,019 | 895,929 | 995,586 | 991,790 | 875,886 | 843,421 | 781,180 | 721,793 | 677,495 | 685,878 | 694,615 | 682,762 | 9,600,354 | 1096 | 9600 |
| 20 | | PF Ld Variance Rate | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $369 | $439 | $488 | $486 | $429 | $413 | $383 | $354 | $332 | $336 | $340 | $335 | $4,704 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -2.02% | -2.09% | -2.13% | -2.13% | -2.13% | -2.08% | -2.10% | -2.08% | -2.06% | -1.99% | -1.97% | -1.98% | | | |
| 23 | | Low Density Discount | -$486 | -$626 | -$740 | -$627 | -$571 | -$498 | -$432 | -$318 | -$256 | -$329 | -$389 | -$406 | -$5,679 | | |
| 24 | -1,008,619 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 25 | | PF Other Energy | | | | | | | | | | | | | | | |
| 26 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 27 | | | | | | | | | | | | | | | | | |
| 28 | | **PF Partial Service** | | | | | | | | | | | | | | | |
| 29 | | LLH Energy Flat | 292,812 | 376,569 | 407,646 | 401,531 | 334,706 | 324,762 | 322,760 | 347,741 | 290,928 | 307,350 | 294,113 | 296,931 | 3,997,849 | 456 | 3,998 |
| 30 | | HLH Energy Flat | 468,002 | 505,457 | 563,482 | 541,076 | 500,348 | 499,916 | 486,488 | 449,661 | 444,801 | 436,120 | 479,809 | 434,003 | 5,809,163 | 663 | 5,809 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $6,738 | $9,200 | $10,456 | $8,617 | $7,256 | $6,693 | $6,123 | $5,300 | $3,081 | $5,529 | $6,276 | $7,079 | $82,348 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $14,700 | $16,928 | $19,699 | $16,059 | $15,166 | $14,058 | $12,838 | $9,911 | $8,874 | $10,715 | $13,804 | $12,890 | $165,641 | | |
| 33 | | GSP Demand | 1,453 | 1,654 | 1,693 | 1,685 | 1,662 | 1,525 | 1,448 | 1,307 | 1,236 | 1,380 | 1,315 | 1,278 | 17,636 | | |
| 34 | | Demand Revenue (34*18) | $2,979 | $3,622 | $3,894 | $3,303 | $3,308 | $2,821 | $2,520 | $1,882 | $1,632 | $2,221 | $2,485 | $2,506 | $33,174 | | |
| 35 | | Load Variance | 1,010,835 | 1,134,069 | 1,251,375 | 1,220,046 | 1,087,221 | 1,090,317 | 1,060,987 | 1,049,283 | 988,300 | 987,361 | 1,011,512 | 961,639 | 12,852,945 | 1467 | 12853 |
| 36 | | Load Variance Revenue (36*21)/1000 | $495 | $556 | $613 | $598 | $533 | $534 | $520 | $514 | $484 | $484 | $496 | $471 | $6,298 | | |
| 37 | -1,133,980 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 38 | | PF Other Energy | | | | | | | | | | | | | | | |
| 39 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | | | | | | | | | | | | | | | |
| 42 | | LLH Energy Flat | 391,915 | 520,023 | 577,456 | 609,659 | 514,460 | 520,497 | 381,897 | 340,167 | 281,881 | 339,246 | 376,183 | 428,295 | 5,281,679 | 603 | 5,282 |
| 43 | | HLH Energy Flat | 561,229 | 645,484 | 785,676 | 769,284 | 718,962 | 749,781 | 547,958 | 430,537 | 395,060 | 452,541 | 492,986 | 572,946 | 7,122,444 | 813 | 7,122 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $9,018 | $12,704 | $14,812 | $13,083 | $11,153 | $10,727 | $7,245 | $5,184 | $2,985 | $6,103 | $8,028 | $10,211 | $111,253 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $17,628 | $21,617 | $27,467 | $22,832 | $21,792 | $21,084 | $14,461 | $9,489 | $7,881 | $11,119 | $14,183 | $17,016 | $206,570 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,405 | 1,787 | 1,982 | 2,038 | 2,005 | 1,889 | 1,407 | 1,283 | 1,148 | 1,279 | 1,367 | 1,470 | 19,060 | | |
| 49 | | Demand Revenue (49*24) | $2,880 | $3,912 | $4,559 | $3,995 | $3,991 | $3,494 | $2,449 | $1,848 | $1,515 | $2,059 | $2,584 | $2,880 | $36,167 | | |
| 50 | -1,309,822 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.90% | -0.79% | -0.81% | -0.81% | -0.79% | -0.73% | -0.99% | -0.90% | -0.83% | -0.75% | -0.68% | -0.93% | | | |
| 53 | | Low-Density Discount | -$265 | -$303 | -$378 | -$325 | -$294 | -$258 | -$240 | -$149 | -$103 | -$145 | -$168 | -$280 | -$2,907 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | | | | | | | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,975 | 39,179 | 0 | 152,052 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,414 | 65,334 | 73,164 | 64,012 | 0 | 247,924 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $805 | $836 | $1,557 | $1,746 | $0 | $4,944 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | | | | | | | | | | | | | | | |
| 62 | | **Pt Townsend HLH** | | | | | | | | | | | | | | | |
| 63 | | **Pt Townsend Demand** | | | | | | | | | | | | | | | |
| 64 | | **Pt Townsend Revenues** | | | | | | | | | | | | | | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF Slice | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.5108% | 18.51% | 1703 | |
| 68 | | Slice rate | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $435,916 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 72 | | LDD Percentage | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | -1.10% | | | |
| 73 | | Low-Density Discount | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$400 | -$4,799 | | |
| 74 | | Slice Other | | | | | | | | | | | | | | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,248 | 1,352 | 1,312 | 1,376 | 1,152 | 1,240 | 1,216 | 1,376 | 1,216 | 1,312 | 1,312 | 1,280 | 15,392 | 2 | 15 |
| 77 | | LLH Energy Revenue | $26 | $28 | $27 | $29 | $24 | $26 | $25 | $29 | $25 | $27 | $27 | $27 | $320 | | |
| 78 | | 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 |
| 79 | | HLH Energy Revenue | $36 | $32 | $35 | $33 | $32 | $36 | $35 | $33 | $35 | $35 | $35 | $33 | $408 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 4 | 8 | 4 | 4 | 4 | 8 | 4 | 56 | | |
| 81 | | Demand Revenue | | | | | | | | | | | | | $0 | | |
| 82 | | Load Variance | 2,976 | 2,888 | 2,976 | 2,976 | 2,688 | 2,968 | 2,880 | 2,976 | 2,880 | 2,976 | 2,976 | 2,880 | 35040 | 4 | 35 |
| 83 | | Load Variance Revenue | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $17 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | | | | | | | | | | | | | $0 | | |
| 88 | | **Total** | $113,758 | $133,564 | $151,069 | $133,024 | $125,196 | $118,659 | $102,058 | $85,762 | $75,326 | $91,821 | $104,739 | $108,859 | $1,343,834 | | |

## TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | A | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Jul 22, 2009 @ 15:58 | | | | | | 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 | | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | | **PF Full Service** | | | | | | | | | | | | | | | |
| 10 | | LLH Energy Flat | 283,578 | 354,922 | 394,600 | 390,289 | 330,326 | 317,074 | 296,897 | 282,531 | 248,811 | 267,121 | 253,314 | 264,571 | 3,684,034 | 421 | 3684 |
| 11 | | HLH Energy Flat | 465,668 | 536,072 | 592,983 | 588,814 | 528,514 | 516,024 | 472,333 | 424,229 | 414,610 | 410,079 | 431,338 | 411,221 | 5,791,885 | 661 | 5792 |
| 12 | | PF Flat LLH Energy Rate | $23.01 | $24.43 | $25.65 | $21.46 | $21.68 | $20.61 | $18.97 | $15.24 | $10.59 | $17.99 | $21.34 | $23.84 | | | |
| 13 | | PF Flat HLH Energy Rate | $31.41 | $33.49 | $34.96 | $29.68 | $30.31 | $28.12 | $26.39 | $22.04 | $19.95 | $24.57 | $28.77 | $29.70 | | | |
| 14 | | LLH Energy Revenue Flat Revenue = 11*13/1000 | $6,525 | $8,671 | $10,121 | $8,376 | $7,161 | $6,535 | $5,632 | $4,306 | $2,635 | $4,806 | $5,406 | $6,307 | $76,481 | | |
| 15 | | HLH Energy Revenue Flat Revenue= 12*14/1000 | $14,627 | $17,953 | $20,731 | $17,476 | $16,019 | $14,511 | $12,465 | $9,350 | $8,271 | $10,076 | $12,410 | $12,213 | $166,101 | | |
| 16 | | Demand | 1,484 | 1,602 | 1,724 | 1,798 | 1,741 | 1,574 | 1,404 | 1,088 | 1,062 | 1,101 | 1,047 | 1,039 | 16,664 | | |
| 17 | | PF GSP Demand Rate | $2.05 | $2.19 | $2.30 | $1.96 | $1.99 | $1.85 | $1.74 | $1.44 | $1.32 | $1.61 | $1.89 | $1.96 | | | |
| 18 | | Demand Revenue = 17*18 | $3,042 | $3,508 | $3,965 | $3,524 | $3,465 | $2,912 | $2,443 | $1,567 | $1,402 | $1,773 | $1,979 | $2,036 | $31,616 | | |
| 19 | | Load Variance | 769,662 | 913,492 | 1,013,058 | 1,003,535 | 881,143 | 855,669 | 793,774 | 734,170 | 689,789 | 702,458 | 709,091 | 695,357 | 9,761,198 | 1114 | 9761 |
| 20 | | PF Ld Variance Rate | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | | | |
| 21 | | Load Variance Revenue = 20*21/1000 | $377 | $448 | $496 | $492 | $432 | $419 | $389 | $360 | $338 | $344 | $347 | $341 | $4,783 | | |
| 22 | | Low Density Discount Percent =30/(15+16+21+22+25+28) | -2.02% | -2.08% | -2.13% | -2.13% | -2.15% | -2.08% | -2.09% | -2.08% | -2.07% | -2.00% | -1.98% | -1.99% | | | |
| 23 | | Low Density Discount | -$496 | -$637 | -$751 | -$638 | -$582 | -$506 | -$438 | -$324 | -$262 | -$340 | -$399 | -$415 | -$5,786 | | |
| 24 | -1,008,619 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 25 | | PF Other Energy | | | | | | | | | | | | | | | |
| 26 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 27 | | | | | | | | | | | | | | | | | |
| 28 | | **PF Partial Service** | | | | | | | | | | | | | | | |
| 29 | | LLH Energy Flat | 310,434 | 372,366 | 411,304 | 408,670 | 341,401 | 331,376 | 329,438 | 354,011 | 296,778 | 317,507 | 290,391 | 302,982 | 4,066,658 | 464 | 4,067 |
| 30 | | HLH Energy Flat | 471,002 | 525,588 | 568,988 | 551,562 | 510,967 | 510,691 | 497,054 | 458,917 | 454,435 | 444,014 | 499,065 | 443,432 | 5,935,715 | 678 | 5,936 |
| 31 | | LLH Energy Revenue Flat (30*13)/1000 | $7,143 | $9,097 | $10,550 | $8,770 | $7,402 | $6,830 | $6,249 | $5,395 | $3,143 | $5,712 | $6,197 | $7,223 | $83,711 | | |
| 32 | | HLH Energy Revenue Flat (31*14)/1000 | $14,794 | $17,602 | $19,892 | $16,370 | $15,487 | $14,361 | $13,117 | $10,115 | $9,066 | $10,909 | $14,358 | $13,170 | $169,242 | | |
| 33 | | GSP Demand | 1,481 | 1,710 | 1,733 | 1,725 | 1,705 | 1,565 | 1,488 | 1,346 | 1,276 | 1,396 | 1,366 | 1,319 | 18,110 | | |
| 34 | | Demand Revenue (34*18) | $3,036 | $3,745 | $3,986 | $3,381 | $3,393 | $2,895 | $2,589 | $1,938 | $1,684 | $2,248 | $2,582 | $2,585 | $34,062 | | |
| 35 | | Load Variance | 1,031,458 | 1,150,010 | 1,260,540 | 1,237,670 | 1,104,535 | 1,107,706 | 1,078,232 | 1,064,810 | 1,003,784 | 1,005,411 | 1,027,047 | 977,119 | 13,048,322 | 1490 | 13048 |
| 36 | | Load Variance Revenue (36*21)/1000 | $505 | $564 | $618 | $606 | $541 | $543 | $528 | $522 | $492 | $493 | $503 | $479 | $6,394 | | |
| 37 | -1,133,980 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 38 | | PF Other Energy | | | | | | | | | | | | | | | |
| 39 | | PF Other revenues | | | | | | | | | | | | | $0 | | |
| 40 | | | | | | | | | | | | | | | | | |
| 41 | | **PF Block Service** | | | | | | | | | | | | | | | |
| 42 | | LLH Energy Flat | 407,170 | 501,586 | 577,456 | 609,659 | 514,460 | 520,497 | 381,897 | 340,167 | 281,881 | 353,957 | 359,890 | 428,295 | 5,276,915 | 602 | 5,277 |
| 43 | | HLH Energy Flat | 545,974 | 664,641 | 785,676 | 769,284 | 718,962 | 749,781 | 547,958 | 430,537 | 395,060 | 441,310 | 506,444 | 572,946 | 7,128,573 | 814 | 7,129 |
| 44 | | LLH Energy Revenue Flat (43*13)/1000 | $9,369 | $12,254 | $14,812 | $13,083 | $11,153 | $10,727 | $7,245 | $5,184 | $2,985 | $6,368 | $7,680 | $10,211 | $111,071 | | |
| 45 | | LLH Energy Revenue Stepped (56*19)/1000 | | | | | | | | | | | | | $0 | | |
| 46 | | HLH Energy Revenue Flat (44*14)/1000 | $17,149 | $22,259 | $27,467 | $22,832 | $21,792 | $21,084 | $14,461 | $9,489 | $7,881 | $10,843 | $14,570 | $17,016 | $206,844 | | |
| 47 | | HLH Energy Revenue Stepped (57*20)/1000 | | | | | | | | | | | | | $0 | | |
| 48 | | GSP Demand | 1,419 | 1,769 | 1,982 | 2,038 | 2,005 | 1,889 | 1,408 | 1,283 | 1,148 | 1,297 | 1,355 | 1,470 | 19,063 | | |
| 49 | | Demand Revenue (49*24) | $2,909 | $3,874 | $4,559 | $3,994 | $3,990 | $3,495 | $2,450 | $1,848 | $1,515 | $2,088 | $2,561 | $2,881 | $36,164 | | |
| 50 | -1,309,822 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 51 | | PF SUMY | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 52 | | Low Density Discount Percent = 70/(59+60+61+62+64) | -0.89% | -0.79% | -0.81% | -0.81% | -0.79% | -0.73% | -0.99% | -0.90% | -0.83% | -0.77% | -0.67% | -0.93% | | | |
| 53 | | Low-Density Discount | -$263 | -$305 | -$378 | -$325 | -$294 | -$258 | -$240 | -$149 | -$103 | -$148 | -$165 | -$280 | -$2,908 | | |
| 54 | | PF Other Energy | | | | | | | | | | | | | 0 | | |
| 55 | | PF Block Other Revenues | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | | | | | | | | |
| 57 | | **Irrigation Mitigation LLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28,360 | 39,538 | 44,977 | 39,178 | 0 | 152,053 | 17 | 152 |
| 58 | | **Irrigation Mitigation HLH** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 45,414 | 65,334 | 71,988 | 64,939 | 0 | 247,675 | 28 | 248 |
| 59 | | **Irrigation Mitigation Revenues** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $805 | $836 | $1,541 | $1,762 | $0 | $4,944 | | |
| 60 | | | | | | | | | | | | | | | | | |
| 61 | | **Pt Townsend LLH** | | | | | | | | | | | | | | | |
| 62 | | **Pt Townsend HLH** | | | | | | | | | | | | | | | |
| 63 | | **Pt Townsend Demand** | | | | | | | | | | | | | | | |
| 64 | | **Pt Townsend Revenues** | | | | | | | | | | | | | | | |
| 65 | | | | | | | | | | | | | | | | | |
| 66 | | PF Slice | | | | | | | | | | | | | | | |
| 67 | | Percent of SLICE | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.511% | 18.51% | 1690 | |
| 68 | | Slice rate | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | | | |
| 69 | | Slice Charges ($000) = 69*70*100 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $36,326 | $435,916 | | |
| 70 | | Monetary Benefits to IOUs ($000) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 71 | -1,091,516 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 72 | | LDD Percentage | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | -1.07% | | | |
| 73 | | Low-Density Discount | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$389 | -$4,663 | | |
| 74 | | Slice Other | | | | | | | | | | | | | | | |
| 75 | | **West Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 76 | | LLH Energy Full Service | 1,312 | 1,288 | 1,312 | 1,376 | 1,152 | 1,240 | 1,216 | 1,376 | 1,216 | 1,376 | 0 | 0 | 12,864 | 1 | 13 |
| 77 | | LLH Energy Revenue | $27 | $27 | $27 | $29 | $24 | $26 | $25 | $29 | $25 | $29 | $0 | $0 | $267 | | |
| 78 | | 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 |
| 79 | | HLH Energy Revenue | $35 | $33 | $35 | $33 | $32 | $36 | $35 | $33 | $35 | $33 | $0 | $0 | $339 | | |
| 80 | | GSP Demand | 4 | 4 | 4 | 4 | 4 | 4 | 8 | 4 | 4 | 4 | 0 | 0 | 44 | | |
| 81 | | Demand Revenue | | | | | | | | | | | | | $0 | | |
| 82 | | Load Variance | 2,976 | 2,888 | 2,976 | 2,976 | 2,688 | 2,968 | 2,880 | 2,976 | 2,880 | 2,976 | 0 | 0 | 29184 | 3 | 29 |
| 83 | | Load Variance Revenue | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $1 | $0 | $0 | $14 | | |
| 84 | | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 85 | | LT SURPLUS FB CRAC | | | | | | | | | | | | | | | |
| 86 | | Netrwork Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 87 | | Other Pre-Subscription revenues | | | | | | | | | | | | | $0 | | |
| 88 | | **Total** | $114,719 | $135,031 | $152,069 | $133,944 | $125,955 | $119,548 | $102,889 | $86,406 | $75,883 | $92,712 | $105,728 | $109,706 | $1,354,591 | | |

**TABLE 4.6.2 REVENUE AT PROPOSED RATES**

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | Revenues at Proposed 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 | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | **PF Full Service** | $2,227 | $2,235 | $3,639 | $2,596 | $2,579 | $2,093 | $1,874 | $1,489 | $1,396 | $2,351 | $2,409 | $2,324 | $27,212 | | |
| 10 | LLH Energy Flat | 250,844 | 286,353 | 372,533 | 356,091 | 292,954 | 273,287 | 259,029 | 246,688 | 217,862 | 268,559 | 245,333 | 284,685 | 3,354,218 | 383 | 3,354 |
| 11 | HLH Energy Flat | 407,981 | 377,601 | 529,332 | 507,651 | 431,350 | 426,128 | 408,092 | 352,756 | 358,976 | 398,206 | 403,309 | 425,382 | 5,026,764 | 574 | 5,027 |
| 12 | 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 | | | |
| 13 | 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 | | | |
| 14 | LLH Energy Revenue Flat= (11*13)/100 | $5,368 | $6,506 | $8,884 | $7,108 | $5,906 | $5,239 | $4,567 | $3,496 | $2,146 | $4,493 | $4,870 | $6,311 | $64,893 | | |
| 15 | HLH Energy Revenue Flat= (12*14)/100 | $11,917 | $11,762 | $17,200 | $14,011 | $12,160 | $11,143 | $10,015 | $7,231 | $6,659 | $9,099 | $10,793 | $11,749 | $133,739 | | |
| 16 | GSP Demand | 1,166 | 1,095 | 1,701 | 1,426 | 1,394 | 1,217 | 1,157 | 1,111 | 1,135 | 1,567 | 1,369 | 1,277 | 15,615 | 2 | 16 |
| 17 | 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 | | | |
| 18 | Demand Revenue= (18*17 | $2,227 | $2,235 | $3,638 | $2,596 | $2,579 | $2,093 | $1,875 | $1,488 | $1,396 | $2,350 | $2,410 | $2,325 | $27,213 | | |
| 19 | PF Ld Variance | 666,394 | 672,419 | 910,999 | 872,428 | 729,881 | 702,637 | 671,689 | 756,946 | 799,339 | 918,757 | 865,138 | 712,436 | 9,279,063 | 1,059 | 9,279 |
| 20 | 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 | | | |
| 21 | Load Variance= (20*21)/100( | $307 | $309 | $419 | $401 | $336 | $323 | $309 | $307 | $308 | $360 | $343 | $327 | $4,049 | | |
| 22 | Low Density Discount Percent=28/(15+16+2 | -3.83% | -3.66% | -3.75% | -3.73% | -3.67% | -3.70% | -3.98% | -3.71% | -3.52% | -3.55% | -3.55% | -4.07% | | | |
| 23 | Low Density Discount | -$758 | -$761 | -$1,131 | -$900 | -$770 | -$696 | -$667 | -$465 | -$370 | -$578 | -$653 | -$842 | -$8,591 | | |
| 24 | LBCRAC True-up/Lookback Adjus | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$603 | -$7,235 | | |
| 25 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 26 | PF Other Revenues | -$169 | $0 | $0 | $0 | $0 | | | | | | | | -$169 | | |
| 27 | | | | | | | | | | | | | | | | |
| 28 | **PF Partial Service** | $3,724 | $3,683 | $5,158 | $4,195 | $3,754 | $3,627 | $2,931 | $2,248 | $2,248 | $3,000 | $3,534 | $3,374 | $41,475 | | |
| 29 | LLH Energy Flat | 79,872 | 90,795 | 112,377 | 107,878 | 90,396 | 91,865 | 80,822 | 79,443 | 75,667 | 92,580 | 82,528 | 85,852 | 1,070,075 | 122 | 1,070 |
| 30 | HLH Energy Flat | 127,480 | 118,245 | 158,653 | 151,997 | 133,163 | 138,684 | 119,422 | 109,656 | 121,177 | 131,293 | 132,068 | 122,171 | 1,564,009 | 179 | 1,564 |
| 31 | LLH Energy Revenue Flat = 30*13/100 | $1,709 | $2,063 | $2,680 | $2,153 | $1,822 | $1,761 | $1,425 | $1,126 | $745 | $1,549 | $1,638 | $1,903 | $20,575 | | |
| 32 | HLH Energy Revenue Flat = 31*14/100 | $3,724 | $3,683 | $5,158 | $4,195 | $3,754 | $3,627 | $2,931 | $2,248 | $2,248 | $3,000 | $3,534 | $3,374 | $41,475 | | |
| 33 | GSP Demand | 342 | 328 | 481 | 440 | 406 | 355 | 331 | 269 | 290 | 337 | 325 | 297 | 4,202 | | |
| 34 | Demand Revenue = 34*1 | $654 | $669 | $1,030 | $801 | $752 | $611 | $536 | $360 | $357 | $506 | $572 | $541 | $7,388 | | |
| 35 | Load Variance | 214,856 | 216,324 | 270,370 | 259,854 | 222,876 | 218,741 | 193,179 | 184,753 | 196,567 | 223,003 | 209,678 | 194,364 | 2,604,565 | 297 | 2,605 |
| 36 | Load Variance = 36*21/100( | $99 | $100 | $128 | $123 | $103 | $101 | $89 | $85 | $90 | $103 | $96 | $89 | $1,205 | | |
| 37 | LBCRAC True-up/Lookback Adjus | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$188 | -$2,252 | | |
| 38 | Low Density Discount Percent= 56/(42+43+ | -2.69% | -2.65% | -2.36% | -2.37% | -2.51% | -2.34% | -2.35% | -2.31% | -2.43% | -2.41% | -2.46% | -2.66% | | | |
| 39 | Low Density Discount | -$167 | -$173 | -$212 | -$172 | -$161 | -$143 | -$117 | -$88 | -$84 | -$124 | -$144 | -$157 | -$1,742 | | |
| 40 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 41 | PF Other Revenue | $0 | $0 | $3 | $3 | $2 | | | | | | | | $8 | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | **PF Block Service** | $4,719 | $4,605 | $5,640 | $4,857 | $4,514 | $3,737 | $4,202 | $2,682 | $2,441 | $2,709 | $2,860 | $4,070 | $47,036 | | |
| 44 | LLH Energy Flat | 114,504 | 127,386 | 134,480 | 136,448 | 118,080 | 112,587 | 125,243 | 127,087 | 106,824 | 109,867 | 96,891 | 118,103 | 1,427,500 | 163 | 1,428 |
| 45 | HLH Energy Flat | 161,568 | 147,840 | 173,472 | 175,968 | 160,128 | 142,900 | 171,239 | 130,828 | 131,616 | 118,569 | 106,867 | 147,340 | 1,768,335 | 202 | 1,768 |
| 46 | LLH Energy Revenue Flat=(45*13)/100 | $2,450 | $2,894 | $3,207 | $2,724 | $2,380 | $2,158 | $2,208 | $1,801 | $1,052 | $1,838 | $1,923 | $2,618 | $27,255 | | |
| 47 | HLH Energy Revenue Flat=(46*14)/100 | $4,719 | $4,605 | $5,640 | $4,857 | $4,514 | $3,737 | $4,202 | $2,682 | $2,441 | $2,709 | $2,860 | $4,070 | $47,036 | | |
| 48 | GSP Demand | 374 | 385 | 417 | 423 | 417 | 341 | 403 | 457 | 500 | 495 | 413 | 368 | 4,993 | | |
| 49 | Demand Revenue=(49*24 | $714 | $785 | $892 | $770 | $771 | $587 | $653 | $613 | $614 | $742 | $727 | $669 | $8,539 | | |
| 50 | LBCRAC True-up/Lookback Adjus | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$320 | -$3,840 | | |
| 51 | Low-Density Discount | $0 | $0 | $0 | $0 | $0 | | | | | | | | $0 | | |
| 52 | PF Other Energy | 0 | 0 | 0 | 0 | 0 | | | | | | | | 0 | 0 | 0 |
| 53 | PF Block Other Revenue | $0 | $0 | $0 | $0 | $0 | | | | | | | | | | |
| 54 | | | | | | | | | | | | | | | | |
| 55 | **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 | $92,568 | | |
| 56 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 349 | |
| 57 | 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 | | | |
| 58 | Slice Charges = 57*58*100 | $7,714 | $7,714 | $7,714 | $7,714 | $7,714 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $7,713 | $92,564 | | |
| 59 | LBCRAC True-up/Lookback Adjus | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$243 | -$2,915 | | |
| 60 | Slice Other Revenues | $0 | $0 | -$286 | $0 | $0 | | | | | | | | -$285 | | |
| 61 | | | | | | | | | | | | | | | | |
| 62 | **East Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 63 | LLH Energy Pre-Sub | 36,570 | 45,106 | 64,189 | 60,054 | 47,683 | 55,768 | 48,804 | 50,954 | 48,701 | 61,609 | 52,733 | 48,484 | 620,655 | 71 | 621 |
| 64 | LLH Energy Revenue | $819 | $1,013 | $1,444 | $1,355 | $1,077 | $1,162 | $902 | $524 | $448 | $780 | $903 | $1,019 | $11,447 | | |
| 65 | HLH Energy Pre-Sub | 60,392 | 60,156 | 90,776 | 85,239 | 71,334 | 87,630 | 74,790 | 75,799 | 83,085 | 91,980 | 92,307 | 72,031 | 945,519 | 108 | 946 |
| 66 | HLH Energy Revenue | $1,485 | $1,478 | $2,236 | $2,095 | $1,758 | $2,012 | $1,542 | $953 | $985 | $1,403 | $1,877 | $1,667 | $19,491 | | |
| 67 | GSP Demand | 176 | 182 | 308 | 262 | 223 | 234 | 214 | 186 | 192 | 245 | 229 | 200 | 2,651 | | |
| 68 | Demand Revenue | $169 | $170 | $280 | $230 | $199 | $241 | $213 | $176 | $176 | $241 | $235 | $204 | $2,535 | | |
| 69 | Load Variance | 78,157 | 80,377 | 114,002 | 105,127 | 86,046 | 137,710 | 119,954 | 121,940 | 123,478 | 149,025 | 140,209 | 117,755 | 1,373,780 | 157 | 1,374 |
| 70 | Load Variance Revenue | $45 | $47 | $66 | $61 | $50 | $78 | $68 | $70 | $70 | $85 | $80 | $67 | $787 | | |
| 71 | Low Density Discount Percen | -2.77% | -2.84% | -2.60% | -2.79% | -2.82% | -5.00% | -4.93% | -4.57% | -4.74% | -4.73% | -4.83% | -4.97% | | | |
| 72 | Low Density Discount | -$70 | -$77 | -$105 | -$104 | -$87 | -$175 | -$134 | -$79 | -$80 | -$119 | -$150 | -$147 | -$1,325 | | |
| 73 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 74 | Other Presubscription revenues | $2 | $2 | $3 | $3 | $2 | | | | | | | | $13 | | |
| 75 | **Irrigation Mitigation** | | | | | | $0 | $0 | $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 | -$3 | $0 | $0 | $1,259 | $1,411 | $2,649 | $2,875 | $0 | $8,191 | | |
| 79 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | -$5 | $0 | $0 | $1,293 | $1,325 | $2,497 | $2,529 | $0 | $7,639 | | |
| 80 | Total | $41,605 | $43,673 | $57,535 | $48,671 | $43,500 | $40,219 | $36,975 | $31,441 | $28,300 | $39,943 | $43,679 | $42,149 | $497,689 | | |

# TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | 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 | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | **PF Full Service** | $2,440 | $2,624 | $3,232 | $2,915 | $2,774 | $2,122 | $1,862 | $1,499 | $1,498 | $2,343 | $2,544 | $2,356 | $28,207 | | |
| 10 | LLH Energy Flat | 256,926 | 300,030 | 365,105 | 369,853 | 295,572 | 270,818 | 263,535 | 247,807 | 221,089 | 289,424 | 247,039 | 287,876 | 3,415,074 | 390 | 3,415 |
| 11 | HLH Energy Flat | 409,926 | 426,668 | 511,562 | 525,154 | 446,340 | 425,282 | 403,695 | 359,686 | 353,216 | 378,836 | 402,715 | 425,019 | 5,068,099 | 579 | 5,068 |
| 12 | PF Flat LLH Energy Rate | $23.01 | $24.43 | $25.65 | $21.46 | $21.68 | $20.61 | $18.97 | $15.24 | $10.59 | $17.99 | $21.34 | $23.84 | | | |
| 13 | PF Flat HLH Energy Rate | $31.41 | $33.49 | $34.96 | $29.68 | $30.31 | $28.12 | $26.39 | $22.04 | $19.95 | $24.57 | $28.77 | $29.70 | | | |
| 14 | LLH Energy Revenue Flat= (11*13)/100 | $5,912 | $7,330 | $9,365 | $7,937 | $6,408 | $5,582 | $4,999 | $3,777 | $2,341 | $5,207 | $5,272 | $6,863 | $70,992 | | |
| 15 | HLH Energy Revenue Flat= (12*14)/100 | $12,876 | $14,289 | $17,884 | $15,587 | $13,529 | $11,959 | $10,654 | $7,927 | $7,047 | $9,308 | $11,586 | $12,623 | $145,268 | | |
| 16 | GSP Demand | 1,190 | 1,198 | 1,405 | 1,487 | 1,394 | 1,147 | 1,070 | 1,041 | 1,135 | 1,455 | 1,346 | 1,202 | 15,070 | | |
| 17 | PF GSP Demand Rate | $2.05 | $2.19 | $2.30 | $1.96 | $1.99 | $1.85 | $1.74 | $1.44 | $1.32 | $1.61 | $1.89 | $1.96 | | | |
| 18 | Demand Revenue= (18*17 | $2,440 | $2,624 | $3,232 | $2,915 | $2,774 | $2,121 | $1,862 | $1,500 | $1,499 | $2,343 | $2,544 | $2,356 | $28,210 | | |
| 19 | PF Ld Variance | 669,814 | 730,157 | 878,853 | 895,914 | 743,124 | 698,937 | 671,474 | 764,764 | 796,577 | 919,892 | 865,875 | 714,885 | 9,350,266 | 1,067 | 9,350 |
| 20 | PF Ld Variance Rate | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | | | |
| 21 | Load Variance= (20*21)/100 | $328 | $357 | $430 | $439 | $364 | $342 | $329 | $331 | $327 | $384 | $366 | $350 | $4,347 | | |
| 22 | Low Density Discount Percent=28/(15+16+2 | -3.86% | -3.70% | -3.73% | -3.71% | -3.70% | -3.73% | -3.96% | -3.73% | -3.54% | -3.55% | -3.54% | -4.09% | | | |
| 23 | Low Density Discount | -$832 | -$909 | -$1,152 | -$998 | -$853 | -$745 | -$707 | -$505 | -$398 | -$612 | -$701 | -$908 | -$9,319 | | |
| 24 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 25 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 26 | PF Other Revenues | | | | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | | | | |
| 28 | **PF Partial Service** | $3,976 | $4,434 | $5,104 | $4,638 | $4,100 | $3,715 | $3,034 | $2,300 | $2,296 | $3,019 | $3,545 | $3,392 | $43,554 | | |
| 29 | LLH Energy Flat | 81,285 | 95,941 | 109,282 | 112,511 | 91,394 | 87,582 | 78,065 | 74,172 | 73,207 | 90,707 | 78,372 | 79,662 | 1,052,180 | 120 | 1,052 |
| 30 | HLH Energy Flat | 126,584 | 132,407 | 145,989 | 156,269 | 135,279 | 132,110 | 114,972 | 104,371 | 115,090 | 122,891 | 123,207 | 114,213 | 1,523,382 | 174 | 1,523 |
| 31 | LLH Energy Revenue Flat = 30*13/100 | $1,870 | $2,344 | $2,803 | $2,414 | $1,981 | $1,805 | $1,481 | $1,130 | $775 | $1,632 | $1,672 | $1,899 | $21,808 | | |
| 32 | HLH Energy Revenue Flat = 31*14/100 | $3,976 | $4,434 | $5,104 | $4,638 | $4,100 | $3,715 | $3,034 | $2,300 | $2,296 | $3,019 | $3,545 | $3,392 | $43,554 | | |
| 33 | GSP Demand | 365 | 358 | 432 | 445 | 406 | 355 | 348 | 285 | 313 | 355 | 322 | 303 | 4,287 | | |
| 34 | Demand Revenue = 34*17 | $748 | $783 | $993 | $872 | $808 | $656 | $605 | $410 | $413 | $571 | $609 | $594 | $8,064 | | |
| 35 | Load Variance | 214,933 | 234,662 | 262,188 | 272,047 | 231,849 | 225,819 | 199,704 | 190,292 | 201,838 | 229,265 | 216,449 | 200,638 | 2,679,684 | 306 | 2,680 |
| 36 | Load Variance = 36*21/100 | $105 | $115 | $128 | $133 | $114 | $111 | $98 | $93 | $98 | $111 | $105 | $98 | $1,310 | | |
| 37 | LBCRAC True-up/Lookback Adjus | | | | | | | | | | | | | $0 | | |
| 38 | Low Density Discount Percent= 56/(42+43+ | -2.62% | -2.50% | -2.45% | -2.38% | -2.42% | -2.41% | -2.46% | -2.37% | -2.55% | -2.52% | -2.52% | -2.67% | | | |
| 39 | Low Density Discount | -$175 | -$192 | -$221 | -$192 | -$169 | -$151 | -$128 | -$93 | -$91 | -$134 | -$149 | -$160 | -$1,857 | | |
| 40 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 41 | PF Other Revenue | -$107 | -$117 | -$131 | -$136 | -$116 | -$113 | -$100 | -$95 | -$101 | -$115 | -$108 | -$100 | -$1,340 | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | **PF Block Service** | $4,611 | $4,423 | $5,438 | $4,508 | $4,438 | $4,176 | $4,519 | $2,883 | $2,626 | $2,913 | $3,087 | $4,376 | $47,996 | | |
| 44 | LLH Energy Flat | 106,189 | 116,270 | 122,909 | 131,065 | 110,031 | 106,978 | 125,243 | 125,535 | 106,388 | 109,867 | 97,150 | 118,103 | 1,375,728 | 157 | 1,376 |
| 45 | HLH Energy Flat | 146,812 | 132,060 | 155,543 | 151,870 | 146,410 | 148,510 | 171,239 | 130,786 | 131,616 | 118,569 | 107,283 | 147,340 | 1,688,038 | 193 | 1,688 |
| 46 | LLH Energy Revenue Flat=(45*13)/100 | $2,443 | $2,840 | $3,153 | $2,813 | $2,385 | $2,205 | $2,376 | $1,913 | $1,127 | $1,977 | $2,073 | $2,816 | $28,120 | | |
| 47 | HLH Energy Revenue Flat=(46*14)/100 | $4,611 | $4,423 | $5,438 | $4,508 | $4,438 | $4,176 | $4,519 | $2,883 | $2,626 | $2,913 | $3,087 | $4,376 | $47,996 | | |
| 48 | GSP Demand | 338 | 342 | 372 | 377 | 379 | 341 | 403 | 457 | 500 | 495 | 414 | 368 | 4,786 | | |
| 49 | Demand Revenue=(49*24 | $692 | $749 | $855 | $740 | $755 | $631 | $702 | $659 | $659 | $797 | $782 | $720 | $8,741 | | |
| 50 | LBCRAC True-up/Lookback Adjus | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 51 | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 52 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 53 | PF Block Other Revenue | | | | | | | | | | | | | | | |
| 54 | | | | | | | | | | | | | | | | |
| 55 | **PF SLICE** | | | | | | | | | | | | | | | |
| 56 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 379 | |
| 57 | Slice Rate | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | | | |
| 58 | Slice Charges = 57*58*10C | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $97,004 | | |
| 59 | LBCRAC True-up/Lookback Adjus | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 60 | Slice Other Revenues | | | | | | | | | | | | | | | |
| 61 | | | | | | | | | | | | | | | | |
| 62 | **East Hub FPS (Pre-Subscription) Sales** | | | | | | | | | | | | | | | |
| 63 | LLH Energy Pre-Sub | 48,311 | 59,076 | 71,350 | 71,090 | 59,268 | 57,319 | 50,063 | 50,774 | 48,422 | 64,168 | 53,122 | 48,854 | 681,817 | 78 | 682 |
| 64 | LLH Energy Revenue | $1,031 | $1,274 | $1,559 | $1,519 | $1,267 | $1,213 | $957 | $541 | $467 | $828 | $926 | $1,047 | $12,629 | | |
| 65 | HLH Energy Pre-Sub | 76,790 | 85,495 | 100,471 | 102,743 | 89,919 | 89,482 | 75,692 | 76,506 | 81,603 | 87,731 | 91,807 | 72,242 | 1,030,481 | 118 | 1,030 |
| 66 | HLH Energy Revenue | $1,855 | $2,089 | $2,486 | $2,468 | $2,167 | $2,092 | $1,615 | $994 | $1,021 | $1,363 | $1,898 | $1,705 | $21,753 | | |
| 67 | GSP Demand | 229 | 239 | 289 | 307 | 281 | 241 | 221 | 191 | 207 | 253 | 235 | 201 | 2,894 | | |
| 68 | Demand Revenue | $245 | $268 | $318 | $320 | $300 | $255 | $225 | $183 | $187 | $251 | $245 | $208 | $3,005 | | |
| 69 | Load Variance | 122,499 | 138,070 | 166,468 | 168,993 | 142,704 | 141,213 | 124,113 | 124,263 | 125,985 | 148,512 | 141,713 | 119,780 | 1,664,313 | 190 | 1,664 |
| 70 | Load Variance Revenue | $71 | $80 | $96 | $98 | $82 | $81 | $71 | $72 | $73 | $86 | $82 | $69 | $961 | | |
| 71 | Low Density Discount Percen | -4.71% | -4.77% | -4.81% | -5.07% | -5.00% | -4.95% | -4.90% | -4.50% | -4.69% | -4.67% | -4.80% | -4.93% | | | |
| 72 | Low Density Discount | -$151 | -$177 | -$214 | -$223 | -$191 | -$180 | -$140 | -$80 | -$82 | -$118 | -$151 | -$149 | -$1,858 | | |
| 73 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 74 | Other Presubscription revenues | | | | | | | | | | | | | $0 | | |
| 75 | **Irrigation Mitigation** | | | | | | | | | | | | | | | |
| 76 | Irrigation Mitigation LLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90,110 | 124,006 | 147,923 | 118,453 | 0 | 480,492 | 55 | 480 |
| 77 | Irrigation Mitigation HLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 142,759 | 211,084 | 235,661 | 201,328 | 0 | 790,832 | 90 | 791 |
| 78 | Irrigation Mitigation Flat Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,321 | $1,500 | $2,737 | $2,979 | $0 | $8,537 | | |
| 79 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,451 | $1,509 | $2,783 | $2,797 | $0 | $8,540 | | |
| 80 | Total | $46,022 | $50,688 | $60,209 | $53,935 | $48,228 | $43,839 | $40,535 | $34,796 | $31,378 | $43,415 | $47,541 | $45,882 | $546,466 | | |

## TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | | 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 | **East Hub PF Billing Determinants** | | | | | | | | | | | | | | | |
| 9 | **PF Full Service** | $2,493 | $2,683 | $3,303 | $2,973 | $2,838 | $2,170 | $1,904 | $1,531 | $1,527 | $2,381 | $2,593 | $2,405 | $28,800 | | |
| 10 | LLH Energy Flat | 265,363 | 304,387 | 373,047 | 377,242 | 302,236 | 277,167 | 269,587 | 254,440 | 227,103 | 284,701 | 250,391 | 294,218 | 3,479,882 | 397 | 3,480 |
| 11 | HLH Energy Flat | 416,290 | 438,749 | 521,990 | 535,221 | 456,078 | 435,003 | 412,742 | 369,302 | 362,987 | 402,968 | 416,923 | 434,274 | 5,202,527 | 594 | 5,203 |
| 12 | PF Flat LLH Energy Rate | $23.01 | $24.43 | $25.65 | $21.46 | $21.68 | $20.61 | $18.97 | $15.24 | $10.59 | $17.99 | $21.34 | $23.84 | | | |
| 13 | PF Flat HLH Energy Rate | $31.41 | $33.49 | $34.96 | $29.68 | $30.31 | $28.12 | $26.39 | $22.04 | $19.95 | $24.57 | $28.77 | $29.70 | | | |
| 14 | LLH Energy Revenue Flat= (11*13)/1000 | $6,106 | $7,436 | $9,569 | $8,096 | $6,552 | $5,712 | $5,114 | $3,878 | $2,405 | $5,122 | $5,343 | $7,014 | $72,347 | | |
| 15 | HLH Energy Revenue Flat= (12*14)/1000 | $13,076 | $14,694 | $18,249 | $15,885 | $13,824 | $12,232 | $10,892 | $8,139 | $7,242 | $9,901 | $11,995 | $12,898 | $149,027 | | |
| 16 | GSP Demand | 1,216 | 1,225 | 1,436 | 1,517 | 1,426 | 1,173 | 1,094 | 1,063 | 1,157 | 1,479 | 1,372 | 1,227 | 15,385 | | |
| 17 | PF GSP Demand Rate | $2.05 | $2.19 | $2.30 | $1.96 | $1.99 | $1.85 | $1.74 | $1.44 | $1.32 | $1.61 | $1.89 | $1.96 | | | |
| 18 | Demand Revenue= (18*17 | $2,494 | $2,683 | $3,302 | $2,974 | $2,837 | $2,170 | $1,904 | $1,530 | $1,527 | $2,382 | $2,593 | $2,405 | $28,801 | | |
| 19 | PF Ld Variance | 684,415 | 746,400 | 897,023 | 913,370 | 759,525 | 715,007 | 686,764 | 781,073 | 812,604 | 939,584 | 883,433 | 730,482 | 9,549,680 | 1,090 | 9,550 |
| 20 | PF Ld Variance Rate | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | $0.49 | | | |
| 21 | Load Variance= (20*21)/1000 | $335 | $365 | $439 | $447 | $372 | $350 | $336 | $339 | $335 | $394 | $374 | $358 | $4,444 | | |
| 22 | Low Density Discount Percent=28/(15+16+2 | -3.86% | -3.70% | -3.73% | -3.72% | -3.70% | -3.73% | -3.96% | -3.74% | -3.56% | -3.56% | -3.56% | -4.09% | | | |
| 23 | Low Density Discount | -$850 | -$933 | -$1,178 | -$1,018 | -$873 | -$763 | -$723 | -$519 | -$410 | -$634 | -$723 | -$927 | -$9,551 | | |
| 24 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 25 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 26 | PF Other Revenues | | | | | | | | | | | | | $0 | | |
| 27 | | | | | | | | | | | | | | | | |
| 28 | **PF Partial Service** | $4,064 | $4,627 | $5,267 | $4,787 | $4,235 | $3,838 | $3,139 | $2,374 | $2,362 | $3,168 | $3,709 | $3,505 | $45,076 | | |
| 29 | LLH Energy Flat | 85,264 | 97,487 | 112,736 | 115,966 | 94,307 | 90,408 | 80,720 | 76,449 | 75,245 | 91,685 | 79,545 | 82,221 | 1,082,033 | 124 | 1,082 |
| 30 | HLH Energy Flat | 129,384 | 138,166 | 150,669 | 161,287 | 139,722 | 136,475 | 118,944 | 107,717 | 118,399 | 128,953 | 128,908 | 118,022 | 1,576,646 | 180 | 1,577 |
| 31 | LLH Energy Revenue Flat = 30*13/1000 | $1,962 | $2,382 | $2,892 | $2,489 | $2,045 | $1,863 | $1,531 | $1,165 | $797 | $1,649 | $1,697 | $1,960 | $22,432 | | |
| 32 | HLH Energy Revenue Flat = 31*14/1000 | $4,064 | $4,627 | $5,267 | $4,787 | $4,235 | $3,838 | $3,139 | $2,374 | $2,362 | $3,168 | $3,709 | $3,505 | $45,076 | | |
| 33 | GSP Demand | 377 | 369 | 446 | 459 | 419 | 367 | 360 | 294 | 322 | 366 | 333 | 313 | 4,425 | | |
| 34 | Demand Revenue = 34*17 | $773 | $809 | $1,026 | $900 | $835 | $678 | $627 | $423 | $425 | $589 | $629 | $614 | $8,329 | | |
| 35 | Load Variance | 221,712 | 241,968 | 270,323 | 280,520 | 239,205 | 233,009 | 206,330 | 195,915 | 207,185 | 236,306 | 223,324 | 207,006 | 2,762,803 | 315 | 2,763 |
| 36 | Load Variance = 36*21/1000 | $109 | $119 | $132 | $137 | $117 | $114 | $101 | $96 | $101 | $115 | $108 | $101 | $1,350 | | |
| 37 | LBCRAC True-up/Lookback Adjust | | | | | | | | | | | | | $0 | | |
| 38 | Low Density Discount Percent= 56/(42+43+4 | -2.57% | -2.46% | -2.41% | -2.34% | -2.38% | -2.37% | -2.42% | -2.34% | -2.52% | -2.47% | -2.48% | -2.63% | | | |
| 39 | Low Density Discount | -$178 | -$195 | -$225 | -$195 | -$172 | -$154 | -$130 | -$95 | -$93 | -$137 | -$153 | -$163 | -$1,889 | | |
| 40 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 41 | PF Other Revenue | -$111 | -$121 | -$135 | -$140 | -$120 | -$117 | -$103 | -$98 | -$104 | -$118 | -$112 | -$104 | -$1,381 | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | **PF Block Service** | $4,438 | $4,610 | $5,438 | $4,508 | $4,438 | $4,176 | $4,519 | $2,883 | $2,626 | $2,746 | $3,274 | $4,376 | $48,031 | | |
| 44 | LLH Energy Flat | 111,697 | 110,670 | 122,909 | 131,065 | 110,031 | 106,978 | 125,243 | 125,535 | 106,388 | 117,561 | 90,638 | 118,103 | 1,376,818 | 157 | 1,377 |
| 45 | HLH Energy Flat | 141,305 | 137,660 | 155,543 | 151,870 | 146,410 | 148,510 | 171,239 | 130,786 | 131,616 | 111,758 | 113,795 | 147,340 | 1,687,832 | 193 | 1,688 |
| 46 | LLH Energy Revenue Flat=(45*13)/1000 | $2,570 | $2,704 | $3,153 | $2,813 | $2,385 | $2,205 | $2,376 | $1,913 | $1,127 | $2,115 | $1,934 | $2,816 | $28,110 | | |
| 47 | HLH Energy Revenue Flat=(46*14)/1000 | $4,438 | $4,610 | $5,438 | $4,508 | $4,438 | $4,176 | $4,519 | $2,883 | $2,626 | $2,746 | $3,274 | $4,376 | $48,031 | | |
| 48 | GSP Demand | 338 | 342 | 372 | 377 | 379 | 341 | 403 | 457 | 500 | 495 | 414 | 368 | 4,786 | | |
| 49 | Demand Revenue=(49*24 | $692 | $749 | $855 | $740 | $755 | $631 | $702 | $659 | $659 | $797 | $782 | $720 | $8,741 | | |
| 50 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 51 | Low-Density Discount | | | | | | | | | | | | | $0 | | |
| 52 | PF Other Energy | | | | | | | | | | | | | 0 | 0 | 0 |
| 53 | PF Block Other Revenue | | | | | | | | | | | | | | | |
| 54 | | | | | | | | | | | | | | | | |
| 55 | **PF SLICE** | | | | | | | | | | | | | | | |
| 56 | Percent of SLICE | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 4.1193% | 376 | |
| 57 | Slice Rate | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | $1,963 | | | |
| 58 | Slice Charges = 57*58*100 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $8,084 | $97,011 | | |
| 59 | LBCRAC True-up/Lookback Adjust | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 60 | Slice Other Revenues | | | | | | | | | | | | | | | |
| 61 | | | | | | | | | | | | | | | | |
| 62 | **East Hub FPS (Pre-Subscription) Sales** | -4.55% | -4.63% | -4.71% | -4.96% | -4.87% | -4.83% | -4.75% | -4.36% | -4.56% | -4.48% | -4.57% | -4.73% | | | |
| 63 | LLH Energy Pre-Sub | 48,808 | 59,694 | 71,524 | 71,208 | 59,272 | 57,502 | 50,596 | 51,333 | 48,917 | 62,298 | 54,173 | 49,844 | 685,169 | 78 | 685 |
| 64 | LLH Energy Revenue | $1,041 | $1,286 | $1,559 | $1,522 | $1,267 | $1,218 | $967 | $545 | $472 | $805 | $945 | $1,069 | $12,697 | | |
| 65 | HLH Energy Pre-Sub | 77,645 | 86,476 | 100,821 | 103,157 | 91,001 | 90,468 | 76,547 | 77,373 | 82,498 | 92,686 | 93,889 | 73,661 | 1,046,222 | 119 | 1,046 |
| 66 | HLH Energy Revenue | $1,591 | $1,810 | $2,109 | $2,064 | $1,854 | $1,825 | $1,379 | $872 | $895 | $1,245 | $1,666 | $1,478 | $18,789 | | |
| 67 | GSP Demand | 232 | 243 | 293 | 311 | 285 | 246 | 225 | 194 | 210 | 256 | 238 | 204 | 2,937 | | |
| 68 | Demand Revenue | $248 | $272 | $323 | $324 | $304 | $258 | $228 | $186 | $190 | $254 | $248 | $211 | $3,047 | | |
| 69 | Load Variance | 124,612 | 140,485 | 169,313 | 171,850 | 145,233 | 143,629 | 126,284 | 126,466 | 128,173 | 151,230 | 144,127 | 121,860 | 1,693,262 | 193 | 1,693 |
| 70 | Load Variance Revenue | $72 | $81 | $98 | $99 | $84 | $83 | $73 | $73 | $74 | $88 | $83 | $70 | $978 | | |
| 71 | Low Density Discount Percen | -4.55% | -4.63% | -4.71% | -4.96% | -4.87% | -4.83% | -4.75% | -4.36% | -4.56% | -4.48% | -4.57% | -4.73% | | | |
| 72 | Low Density Discount | -$134 | -$160 | -$193 | -$199 | -$171 | -$163 | -$126 | -$73 | -$74 | -$107 | -$135 | -$134 | -$1,669 | | |
| 73 | Wind Integration Service | | | | | | | | | | | | | $0 | | |
| 74 | Other Presubscription revenues | | | | | | | | | | | | | $0 | | |
| 75 | **Irrigation Mitigation** | | | | | | | | | | | | | | | |
| 76 | Irrigation Mitigation LLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 90,110 | 124,006 | 148,154 | 117,248 | 0 | 479,518 | 55 | 480 |
| 77 | Irrigation Mitigation HLH | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 142,759 | 211,084 | 234,548 | 199,640 | 0 | 788,031 | 90 | 788 |
| 78 | Irrigation Mitigation Flat Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,321 | $1,500 | $2,737 | $2,924 | $0 | $8,482 | | |
| 79 | Irrigation Mitigation Stepped Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $1,451 | $1,509 | $2,769 | $2,797 | $0 | $8,527 | | |
| 80 | Total | $46,383 | $51,301 | $60,765 | $54,316 | $48,652 | $44,241 | $40,890 | $35,147 | $31,649 | $43,965 | $48,065 | $46,353 | $551,728 | | |

# TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | Revenues at Proposed 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (46.46) | (46.46) | (46.46) | (47.22) | (47.45) | (47.45) | (47.56) | (47.56) | (47.67) | (47.67) | (48.00) | (48.00) | (49.46) | | |
| 10 | Energy (MWhr) | 2,357,543 | 2,669,837 | 3,476,522 | 4,317,495 | 3,368,129 | 3,127,975 | 2,701,817 | 2,484,845 | 2,481,228 | 2,644,717 | 2,528,174 | 2,314,738 | 34,473,020 | 3,935 | 34,473 |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$113,539 | -$129,016 | -$167,543 | -$213,478 | -$168,287 | -$156,379 | -$135,368 | -$123,944 | -$123,530 | -$130,913 | -$126,651 | -$116,493 | -$1,705,142 | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | | | | | | | | | | | | | | | |
| 14 | IP LBCRAC True-up Revenue ($000) | | | | | | | | | | | | | | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 751 | 863 | 770 | 770 | 870 | 940 | 788 | 1,003 | 808 | 959 | 978 | 796 | 10,296 | | |
| 17 | HLH Energy (MWhr) | 171,719 | 239,003 | 224,011 | 217,419 | 187,526 | 143,338 | 108,238 | 180,235 | 96,442 | 134,718 | 158,477 | 79,495 | 1,940,621 | 222 | 1,941 |
| 18 | LLH Energy (MWhr) | -129,870 | -42,585 | -78,946 | -90,293 | -74,210 | -146,665 | -44,319 | 9,357 | -19,103 | 21,631 | -5,171 | -92,823 | -692,997 | -79 | -693 |
| 19 | Energy (aMW) | 56 | 272 | 195 | 171 | 169 | -4 | 89 | 255 | 107 | 210 | 206 | -19 | 1,707 | 142 | 1,248 |
| 20 | Revenue ($ Thousand) | $3,951 | $10,923 | $10,768 | $10,811 | $10,175 | $7,503 | $7,331 | $7,536 | $4,027 | $6,514 | $7,981 | $3,980 | $91,498 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,245 | 1,273 | 1,273 | 14,996 | | |
| 24 | HLH Energy (MWhr) | 346,350 | 334,728 | 345,886 | 345,886 | 312,413 | 345,886 | 334,263 | 345,886 | 334,728 | 345,886 | 421,922 | 408,312 | 4,222,146 | 482 | 4,222 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 465 | 567 | 567 | 5,783 | 482 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | 357,945 | 445,952 | 403,914 | 829,746 | 136,700 | 796,138 | 502,329 | 613,200 | 616,800 | 72,800 | 41,600 | 40,000 | 4,857,124 | 554 | 4,857 |
| 30 | Monthly Trading Floor Committed Sales ($000) | $19,669 | $21,826 | $22,239 | $33,118 | $4,668 | $22,333 | $18,584 | $24,159 | $24,990 | $4,878 | $2,174 | $2,090 | $200,727 | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | | | | | | | 791,866 | 1,347,854 | 1,885,286 | 1,060,593 | 47,628 | 205,501 | 5,338,728 | 609 | 5,339 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | | | | | | | $20,412 | $28,616 | $40,960 | $29,549 | $1,449 | $6,029 | $127,015 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | -98,215 | -122,762 | -143,872 | -1,904 | -29,136 | -121,373 | | | | | | | -517,262 | -59 | -517 |
| 36 | Revenue reversals ($000) | -$5,185 | -$5,930 | -$8,411 | $0 | -$1,083 | -$3,450 | | | | | | | -$24,059 | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $261 | $299 | $337 | $272 | $269 | $238 | $206 | $221 | $215 | $260 | $291 | $264 | $3,134 | | |
| 41 | **IOU Power Buyback/Deferred LB CRAC expense** | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | Renewable HLH (MWH) | 34,311 | 34,324 | 41,382 | 47,002 | 21,638 | 38,693 | 28,678 | 26,230 | 27,059 | 28,177 | 24,661 | 24,297 | 376,451 | 43 | 376 |
| 44 | Renewable LLH (MWH) | 6,519 | 6,070 | 9,789 | 9,829 | 8,209 | 28,514 | 23,689 | 24,297 | 26,321 | 25,352 | 22,458 | 19,996 | 211,044 | 24 | 211 |
| 45 | Renewable Expense ($000) (included in Program Expense Forecast) | $2,017 | $2,071 | $2,587 | $2,933 | $1,681 | $3,394 | $2,694 | $2,669 | $2,727 | $2,744 | $2,437 | $2,317 | $30,273 | | |
| 46 | | | | | | | | | | | | | | | | |
| 47 | Power Purchases Bookouts (MWH) | -98,215 | -122,762 | -143,872 | -1,904 | -29,136 | -121,373 | 0 | 0 | 0 | 0 | 0 | 0 | -517,262 | -59 | -517 |
| 48 | Power Purchases Reversals ($000) | -$5,185 | -$5,930 | -$8,411 | $0 | -$1,083 | -$3,450 | $0 | $0 | $0 | $0 | $0 | $0 | -$24,059 | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | Augmentation Power Purchases (MWH) | | | | | | | | | | | | | 0 | 0 | 0 |
| 51 | Augmentation Power Purchases ($000) | | | | | | | | | | | | | $0 | | |
| 52 | | | | | | | | | | | | | | | | |
| 53 | Other Committed Power Purchases (MWH) | 5,669 | 6,860 | 3,092 | 1,773 | 9,682 | 9,801 | 15,033 | 24,268 | 44,612 | 27,856 | 15,507 | 5,796 | 169,950 | 19 | 170 |
| 54 | Balancing Power Purchases (MWH) | | | | | | | 420 | 17,608 | - | 10,895 | 435,023 | 207,637 | 671,584 | 77 | 672 |
| 55 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | 502,816 | 612,716 | 937,212 | 138,711 | 642,173 | 626,970 | 118,824 | - | - | 131,200 | 291,000 | 168,000 | 4,169,622 | 476 | 4,170 |
| 56 | Other Committed Purchase Power Expense ($000) | **$660** | **$564** | **$793** | **$687** | **$390** | **$726** | **$952** | **$991** | **$1,118** | **$1,640** | **$330** | **$513** | **$9,365** | | |
| 57 | Balancing Purchase Power Expense ($000) | | | | | | | $11 | $451 | $0 | $319 | $14,700 | $6,656 | **$22,136** | | |
| 58 | Trading Floor Purchase Power Expense ($000) | **$24,625** | **$30,061** | **$61,783** | **$4,924** | **$26,086** | **$18,938** | **$3,245** | **$0** | **$0** | **$3,850** | **$10,646** | **$5,636** | **$189,793** | | |
| 59 | | | | | | | | | | | | | | | | |
| 60 | Lookback adjustment | $4,665 | $5,750 | $7,102 | $7,986 | $6,592 | $6,178 | $5,357 | $4,969 | $5,019 | $6,075 | $5,774 | $5,303 | $70,768 | | |
| 61 | Residential Exchange Power Purchase | 2,357,543 | 2,669,837 | 3,476,522 | 4,317,495 | 3,368,129 | 3,127,975 | 2,701,817 | 2,484,845 | 2,481,228 | 2,644,717 | 2,528,174 | 2,314,738 | 34,473,020 | 3,935 | 34,473 |
| 62 | Residential Exchange cost | $129,830 | $147,028 | $191,452 | $237,764 | $185,483 | $172,258 | $148,789 | $136,840 | $136,641 | $145,645 | $139,227 | $127,473 | $1,898,429 | | |

## TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | (47.67) | | |
| 10 | Energy (MWhr) | 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 | | |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$136,569 | -$152,448 | -$194,760 | -$228,103 | -$211,152 | -$193,672 | -$171,400 | -$117,589 | -$92,873 | -$91,470 | -$116,758 | -$148,786 | -$1,855,580 | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | 299,490 | 290,244 | 299,490 | 299,490 | 270,546 | 299,088 | 289,842 | 299,490 | 289,842 | 299,490 | 299,490 | 289,842 | 3,526,344 | 403 | 3,526 |
| 14 | IP LBCRAC True-up Revenue ($000) | $9,753 | $10,033 | $10,923 | $11,429 | $10,296 | $10,745 | $9,381 | $8,757 | $8,591 | $10,000 | $11,138 | $10,805 | $121,852 | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 851 | 963 | 870 | 870 | 870 | 788 | 788 | 988 | 770 | 785 | 938 | 758 | 10,239 | | |
| 17 | HLH Energy (MWhr) | 54,962 | 98,624 | 142,515 | 159,523 | 125,172 | 94,802 | 100,158 | 178,576 | 89,776 | 67,322 | 145,400 | 74,435 | 1,331,265 | 152 | 1,331 |
| 18 | LLH Energy (MWhr) | -129,189 | -50,621 | -16,121 | -34,115 | -13,973 | -47,213 | -40,587 | 9,357 | -47,376 | -38,354 | -3,129 | -87,730 | -499,051 | -57 | -499 |
| 19 | Energy (aMW) | -100 | 67 | 170 | 169 | 165 | 64 | 83 | 253 | 59 | 39 | 191 | -18 | 1,141 | 95 | 832 |
| 20 | Revenue ($ Thousand) | $4,862 | $11,176 | $11,346 | $11,335 | $10,793 | $8,156 | $8,055 | $8,681 | $4,907 | $4,903 | $7,705 | $4,860 | $96,778 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,273 | 1,240 | 1,240 | 15,210 | | |
| 24 | HLH Energy (MWhr) | 422,490 | 408,312 | 421,922 | 421,922 | 381,091 | 421,922 | 407,745 | 421,922 | 408,312 | 421,922 | 392,088 | 379,440 | 4,909,088 | 560 | 4,909 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 567 | 527 | 527 | 6,725 | 560 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | | | | | | | | | | | | | | | |
| 30 | Monthly Trading Floor Committed Sales ($000) | | | | | | | | | | | | | | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | 264,582 | 441,458 | 619,865 | 1,297,484 | 1,051,699 | 1,335,168 | 1,823,398 | 3,066,531 | 2,349,974 | 1,750,318 | 566,422 | 272,940 | 14,839,839 | 1,694 | 14,840 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | $8,514 | $15,446 | $23,222 | $55,912 | $42,798 | $52,434 | $63,709 | $102,412 | $78,428 | $66,440 | $24,115 | $11,201 | $544,632 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | | | | | | | | | | | | | | | |
| 36 | Revenue reversals ($000) | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $228 | $247 | $287 | $230 | $214 | $196 | $156 | $193 | $207 | $222 | $270 | $216 | $2,665 | | |
| 41 | **IOU Power Buyback/Deferred LB CRAC expense** | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | 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 |
| 44 | 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 |
| 45 | Renewable Expense ($000) (included in Program Expense Forecast) | $2,431 | $2,444 | $2,371 | $2,250 | $2,149 | $3,453 | $2,750 | $2,869 | $2,760 | $2,764 | $2,435 | $2,318 | $30,994 | | |
| 46 | | | | | | | | | | | | | | | | |
| 47 | Power Purchases Bookouts (MWH) | | | | | | | | | | | | | | | |
| 48 | Power Purchases Reversals ($000) | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | Augmentation Power Purchases (MWH) | 353,933 | 342,992 | 353,933 | 353,933 | 319,681 | 353,457 | 342,516 | 353,933 | 342,516 | 353,933 | 353,933 | 342,516 | 4,167,276 | 476 | 4,167 |
| 51 | Augmentation Power Purchases ($000) | $15,126 | $14,659 | $15,126 | $15,126 | $13,662 | $15,106 | $14,638 | $15,126 | $14,638 | $15,126 | $15,126 | $14,638 | $178,100 | | |
| 52 | | | | | | | | | | | | | | | | |
| 53 | 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 |
| 54 | Balancing Power Purchases (MWH) | 67,363 | 242,691 | 276,916 | 331,699 | 250,469 | 151,184 | 151,073 | 2,469 | 7,222 | 23,487 | 131,834 | 71,560 | 1,707,967 | 195 | 1,708 |
| 55 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | | | | | | | | | | | | | | | |
| 56 | Other Committed Purchase Power Expense ($000) | $384 | $390 | $370 | $439 | $473 | $145 | $124 | $175 | $162 | $117 | $167 | $118 | $3,065 | | |
| 57 | Balancing Purchase Power Expense ($000) | $2,038 | $11,378 | $13,579 | $16,913 | $13,112 | $8,763 | $8,621 | $85 | $301 | $899 | $5,785 | $3,091 | $84,566 | | |
| 58 | Trading Floor Purchase Power Expense ($000) | | | | | | | | | | | | | | | |
| 59 | | | | | | | | | | | | | | | | |
| 60 | Lookback adjustment | | | | | | | | | | | | | | | |
| 61 | 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 |
| 62 | Residential Exchange cost | $155,931 | $174,061 | $222,371 | $260,442 | $241,087 | $221,129 | $195,700 | $134,260 | $106,040 | $104,438 | $133,312 | $169,880 | $2,118,652 | | |

# TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | 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 | **Investor-Owned Utilities Residential Exchange** | | | | | | | | | | | | | | | |
| 9 | Residential Exchange Rate | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | (49.69) | | |
| 10 | Energy (MWhr) | 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 | | |
| 11 | Residential Exchange Revenue ($000) = (12+13)*14 | -$143,207 | -$159,581 | -$203,565 | -$237,644 | -$220,129 | -$201,997 | -$181,508 | -$125,514 | -$100,357 | -$99,176 | -$125,231 | -$158,056 | ($1,955,964) | | |
| 12 | **Direct-Service Industries (IP-02 & FPS)** | | | | | | | | | | | | | | | |
| 13 | IP LBCRAC True-up (MWH) | 299,490 | 290,244 | 299,490 | 299,490 | 270,546 | 299,088 | 289,842 | 299,490 | 289,842 | 299,490 | 299,490 | 289,842 | 3,526,344 | 403 | 3,526 |
| 14 | IP LBCRAC True-up Revenue ($000) | $9,722 | $10,057 | $10,923 | $11,429 | $10,296 | $10,745 | $9,381 | $8,757 | $8,591 | $9,970 | $11,176 | $10,805 | $121,852 | | |
| 15 | **PAC capacity, WNP-3 and other L-T contracts** | | | | | | | | | | | | | | | |
| 16 | Demand (MW) | 828 | 947 | 854 | 854 | 854 | 772 | 772 | 965 | 770 | 800 | 784 | 183 | 9,383 | | |
| 17 | HLH Energy (MWhr) | 49,873 | 97,242 | 139,155 | 155,843 | 121,972 | 91,281 | 96,708 | 173,826 | 89,776 | 67,498 | 78,083 | -6,696 | 1,154,561 | 132 | 1,155 |
| 18 | LLH Energy (MWhr) | -119,795 | -44,396 | -7,954 | -26,149 | -7,244 | -39,709 | -35,127 | 13,899 | -47,376 | -38,596 | -61,515 | -6,599 | -420,561 | -48 | -421 |
| 19 | Energy (aMW) | -94 | 73 | 176 | 174 | 171 | 69 | 86 | 252 | 59 | 39 | 22 | -18 | 1,010 | 84 | 734 |
| 20 | Revenue ($ Thousand) | $4,862 | $11,026 | $11,196 | $11,185 | $10,644 | $8,006 | $7,905 | $8,465 | $4,907 | $4,903 | $5,280 | $59 | $88,437 | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | **Contractual Obligations (CER)** | | | | | | | | | | | | | | | |
| 23 | Demand (MW) | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 1,240 | 14,880 | | |
| 24 | HLH Energy (MWhr) | 392,615 | 379,440 | 392,088 | 392,088 | 354,144 | 392,088 | 378,913 | 392,088 | 379,440 | 392,088 | 384,648 | 372,240 | 4,601,880 | 525 | 4,602 |
| 25 | LLH Energy (MWhr) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | Energy (aMW) | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 524 | 6,288 | 525 | |
| 27 | Revenue ($ Thousand) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | $0 | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | Monthly Trading Floor Committed Sales (MWH) | | | | | | | | | | | | | | | |
| 30 | Monthly Trading Floor Committed Sales ($000) | | | | | | | | | | | | | | | |
| 31 | Monthly Trading Floor Balancing Sales (MWH) | 533,732 | 499,896 | 706,318 | 1,486,068 | 1,142,705 | 1,506,518 | 1,671,295 | 2,727,700 | 2,172,688 | 1,810,013 | 727,604 | 355,182 | 15,339,720 | 1,751 | 15,340 |
| 32 | Monthly Trading Floor Balancing Sales ($000) | $22,235 | $21,049 | $30,042 | $64,900 | $48,333 | $61,709 | $60,252 | $93,306 | $73,618 | $71,649 | $31,736 | $15,114 | $593,944 | | |
| 33 | Other Monthly Sales (MWH) | | | | | | | | | | | | | | | |
| 34 | Other Monthly Sales ($000) | | | | | | | | | | | | | | | |
| 35 | FPS Bookouts | | | | | | | | | | | | | | | |
| 36 | Revenue reversals ($000) | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | |
| 38 | **Power Purchases** | | | | | | | | | | | | | | | |
| 39 | **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 |
| 40 | **ERE Augmentation Purchase Expense** | $174 | $189 | $219 | $175 | $164 | $150 | $119 | $136 | $139 | $165 | $205 | $164 | $1,998 | | |
| 41 | **IOU Power Buyback/Deferred LB CRAC expense** | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | |
| 43 | 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 |
| 44 | 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 |
| 45 | Renewable Expense ($000) (included in Program Expense Forecast) | $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 | | |
| 46 | | | | | | | | | | | | | | | | |
| 47 | Power Purchases Bookouts (MWH) | | | | | | | | | | | | | | | |
| 48 | Power Purchases Reversals ($000) | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | Augmentation Power Purchases (MWH) | 506,186 | 490,537 | 506,186 | 506,186 | 457,200 | 505,505 | 489,857 | 506,186 | 489,857 | 506,186 | 506,186 | 489,857 | 5,959,928 | 680 | 5,960 |
| 51 | Augmentation Power Purchases ($000) | $23,020 | $22,309 | $23,020 | $23,020 | $20,793 | $22,989 | $22,278 | $23,020 | $22,278 | $23,020 | $23,020 | $22,278 | $271,045 | | |
| 52 | | | | | | | | | | | | | | | | |
| 53 | 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 |
| 54 | Balancing Power Purchases (MWH) | 4,402 | 156,897 | 208,567 | 283,867 | 214,360 | 131,400 | 175,784 | 16,417 | 25,379 | 4,283 | 51,699 | 34,874 | 1,307,928 | 149 | 1,308 |
| 55 | NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590 | | | | | | | | | | | | | | | |
| 56 | Other Committed Purchase Power Expense ($000) | $54 | $60 | $40 | $109 | $143 | $145 | $124 | $175 | $162 | $117 | $167 | $118 | $1,415 | | |
| 57 | Balancing Purchase Power Expense ($000) | $198 | $8,811 | $11,273 | $15,047 | $11,674 | $7,919 | $9,710 | $642 | $1,107 | $173 | $2,588 | $1,548 | $70,692 | | |
| 58 | Trading Floor Purchase Power Expense ($000) | | | | | | | | | | | | | | | |
| 59 | | | | | | | | | | | | | | | | |
| 60 | Lookback adjustment | | | | | | | | | | | | | | | |
| 61 | 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 |
| 62 | Residential Exchange cost | $162,872 | $181,494 | $231,518 | $270,277 | $250,356 | $229,734 | $206,432 | $142,749 | $114,137 | $112,794 | $142,427 | $179,760 | $2,224,550 | | |

# TABLE 4.6.2 REVENUE AT PROPOSED RATES

| | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | Revenues at Proposed 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $8 | $165 | $129 | $0 | $0 | $125 | $125 | $125 | $125 | $125 | $125 | $125 | $1,178 | | |
| 10 | Energy Imbalance | $452 | $683 | $790 | $650 | $265 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $2,840 | | |
| 11 | Federal RAS for Generation Dropping | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $396 | | |
| 12 | Synchronous Condensing | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $341 | $4,091 | 16 | 136337 |
| 13 | Station Service | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $174 | $2,089 | 9 | 76421 |
| 14 | Regulating Reserves | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $1,097 | $13,158 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $2,395 | $2,254 | $2,624 | $2,786 | $2,442 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $2,742 | $31,694 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $616 | $7,397 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $738 | $738 | $738 | $840 | $911 | $1,028 | $1,201 | $1,201 | $1,492 | $1,492 | $2,120 | $2,120 | $14,617 | | |
| 18 | **Total Interbusiness Line** | **$5,854** | **$6,101** | **$6,542** | **$6,538** | **$5,878** | **$6,156** | **$6,329** | **$6,329** | **$6,619** | **$6,619** | **$7,247** | **$7,247** | **$77,460** | 24 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $158 | $198 | $359 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $303 | $3,438 | | |
| 22 | **Total Reserve Services** | **$158** | **$198** | **$359** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$303** | **$3,438** | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$6,012** | **$6,300** | **$6,901** | **$6,840** | **$6,181** | **$6,459** | **$6,631** | **$6,631** | **$6,922** | **$6,922** | **$7,550** | **$7,550** | **$80,897** | 24 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $882 | $848 | $864 | $858 | $845 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $9,646 | | |
| 29 | Slice True-Up (and Implementation costs) | | | | | | | | | | | | $5,370 | $5,370 | | |
| 30 | Misc. Generation | $288 | $328 | $395 | $614 | $308 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,927 | | |
| 31 | Energy Efficiency Rev's | $2,431 | $639 | $1,111 | $931 | $780 | $605 | $801 | $901 | $1,000 | $1,000 | $1,500 | $2,800 | $14,500 | | |
| 32 | Green Tags and Green Premiums Bulk | $56 | $162 | $325 | $5 | $198 | $90 | $90 | $90 | $90 | $90 | $90 | $147 | $1,434 | | |
| 33 | Green Premium West | $150 | $145 | $147 | $147 | $133 | $24 | $23 | $24 | $23 | $24 | $24 | $23 | $886 | | |
| 34 | Green Premium East | $111 | $108 | $111 | $111 | $100 | $113 | $110 | $113 | $110 | $113 | $113 | $110 | $1,323 | | |
| 35 | 4(h)(10)c credit | $7,547 | $6,954 | $7,088 | $7,029 | $7,894 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $6,009 | $78,578 | | |
| 36 | Network Wind Integration&Shaping | $170 | $170 | $170 | $170 | $170 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,989 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$12,018** | **$9,737** | **$10,594** | **$10,249** | **$10,813** | **$8,387** | **$8,598** | **$8,731** | **$8,845** | **$8,868** | **$9,360** | **$16,055** | **$122,254** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$5,849** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$6,004** | **$5,804** | **$5,804** | **$5,804** | **$5,641** | **$5,641** | **$70,564** | | |
| 43 | **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 4.6.2 REVENUE AT PROPOSED RATES

| | B | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AE | AF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $400 | | |
| 10 | Energy Imbalance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 11 | Federal RAS for Generation Dropping | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $612 | | |
| 12 | Synchronous Condensing | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,959 | 5 | 40301 |
| 13 | Station Service | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $3,229 | 9 | 79567 |
| 14 | Regulating Reserves | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $7,699 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $3,197 | $3,197 | $3,197 | $3,197 | $3,197 | $3,197 | $2,052 | $2,052 | $2,052 | $2,052 | $2,052 | $2,052 | $31,495 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $6,203 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $3,214 | $38,574 | | |
| 18 | **Total Interbusiness Line** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$90,171** | 14 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 22 | **Total Reserve Services** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$8,087** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$6,942** | **$90,171** | 14 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $731 | $710 | $710 | $710 | $711 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $8,921 | | |
| 29 | Slice True-Up (and Implementation costs) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($5,282) | ($5,282) | | |
| 30 | Misc. Generation | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,420 | | |
| 31 | 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 | | |
| 32 | Green Tags and Green Premiums Bulk | $404 | $378 | $357 | $320 | $296 | $589 | $446 | $489 | $467 | $477 | $423 | $394 | $5,040 | | |
| 33 | Green Premium West | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 34 | Green Premium East | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 35 | 4(h)(10)c credit | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $8,057 | $96,689 | | |
| 36 | Network Wind Integration&Shaping | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,953 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$11,390** | **$11,343** | **$11,323** | **$11,286** | **$11,262** | **$11,558** | **$11,435** | **$11,506** | **$11,504** | **$12,899** | **$12,837** | **$7,498** | **$135,842** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$7,418** | **$89,018** | | |
| 43 | **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 REVENUE AT PROPOSED RATES

| | B | AG | AH | AI | AJ | AK | AL | AM | AN | AO | AP | AQ | AR | AS | AT | AU |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jul 17, 2009 @ 12:18 | | | | | | Revenues at Proposed 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 | **GEN INPUTS:** | | | | | | | | | | | | | | | |
| 9 | Redispatch | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $33 | $400 | | |
| 10 | Energy Imbalance | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 11 | Federal RAS for Generation Dropping | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $51 | $612 | | |
| 12 | Synchronous Condensing | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,959 | 5 | 40,301 |
| 13 | Station Service | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $269 | $3,229 | 9 | 79,567 |
| 14 | Regulating Reserves | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $642 | $7,699 | | |
| 15 | Operating Reserves - Spinning & Supplemental | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $2,199 | $26,387 | | |
| 16 | COE/BOR Network/Delivery Facilities Segmentation | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $517 | $6,203 | | |
| 17 | Within-Hour Balancing Service for Wind Integration | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $4,687 | $56,246 | | |
| 18 | **Total Interbusiness Line** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$102,735** | 14 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | **RESERVE SERVICES:** | | | | | | | | | | | | | | | |
| 21 | External | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 22 | **Total Reserve Services** | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | **TOTAL Ancillary and Reserves** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$8,561** | **$102,735** | 14 | |
| 25 | | | | | | | | | | | | | | | | |
| 26 | **OTHER REVENUES** | | | | | | | | | | | | | | | |
| 27 | Downstream Benefits and Storage (MWh) | 70,190 | 10,264 | 23,245 | 52,260 | 53,085 | 152,833 | 174,525 | 215,620 | 206,324 | 230,778 | 187,731 | 157,687 | 1,534,543 | 175 | 1,535 |
| 28 | Downstream Benefits and Pumping Power $$$ | $731 | $710 | $710 | $710 | $711 | $714 | $733 | $762 | $782 | $800 | $792 | $765 | $8,921 | | |
| 29 | Slice True-Up (and Implementation costs) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $10,942 | $10,942 | | |
| 30 | Misc. Generation | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $285 | $3,420 | | |
| 31 | 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 | | |
| 32 | Green Tags and Green Premiums Bulk | $404 | $378 | $357 | $320 | $296 | $589 | $446 | $489 | $467 | $477 | $423 | $394 | $5,040 | | |
| 33 | Green Premium West | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 34 | Green Premium East | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | |
| 35 | 4(h)(10)c credit | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $8,497 | $101,969 | | |
| 36 | Network Wind Integration&Shaping | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $163 | $1,953 | | |
| 37 | Colville and Spokane Settlements | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $383 | $4,600 | | |
| 38 | LB CRAC True-up | | | | | | | | | | | | | | | |
| 39 | Aluminum Hedging | | | | | | | | | | | | | | | |
| 40 | **TOTAL OTHER REVENUES** | **$11,830** | **$11,783** | **$11,763** | **$11,726** | **$11,702** | **$11,998** | **$11,875** | **$11,946** | **$11,944** | **$13,339** | **$13,277** | **$24,162** | **$157,345** | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | **Trading Floor Transmission** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$7,363** | **$88,352** | | |
| 43 | **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

**Surplus Sales FY 2010**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Monthly Hours** | 744 | 721 | 744 | 744 | 672 | 743 | 720 | 744 | 720 | 744 | 744 | 720 | **8,760** |
| **Surplus Sales (aMW)** | 356 | 612 | 833 | 1,744 | 1,565 | 1,797 | 2,532 | 4,122 | 3,264 | 2,353 | 761 | 379 | **1,694** |
| **Secondary Revenue ($ Thousand)** | 8,514 | 15,446 | 23,222 | 55,912 | 42,798 | 52,434 | 63,709 | 102,412 | 78,428 | 66,440 | 24,115 | 11,201 | **544,632** |
| **Average Sales Price ($/MWh)** | $ 32.18 | $ 34.99 | $ 37.46 | $ 43.09 | $ 40.69 | $ 39.27 | $ 34.94 | $ 33.40 | $ 33.37 | $ 37.96 | $ 42.57 | $ 41.04 | **$ 36.70** |

**Surplus Sales FY 2011**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Monthly Hours** | 744 | 721 | 744 | 744 | 672 | 743 | 720 | 744 | 720 | 744 | 744 | 720 | **8,760** |
| **Surplus Sales (aMW)** | 717 | 693 | 949 | 1,997 | 1,700 | 2,028 | 2,321 | 3,666 | 3,018 | 2,433 | 978 | 493 | **1,751** |
| **Secondary Revenue ($ Thousand)** | 22,235 | 21,049 | 30,042 | 64,900 | 48,333 | 61,709 | 60,252 | 93,306 | 73,618 | 71,649 | 31,736 | 15,114 | **593,944** |
| **Average Sales Price ($/MWh)** | $ 41.66 | $ 42.11 | $ 42.53 | $ 43.67 | $ 42.30 | $ 40.96 | $ 36.05 | $ 34.21 | $ 33.88 | $ 39.58 | $ 43.62 | $ 42.55 | **$ 38.72** |

## Table 4.8.2: Balancing Purchases

**Balancing Purchases FY 2010**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Monthly Hours** | 744 | 721 | 744 | 744 | 672 | 743 | 720 | 744 | 720 | 744 | 744 | 720 | **8,760** |
| **Balancing Purchases (aMW)** | 76 | 326 | 358 | 437 | 369 | 196 | 212 | 3 | 12 | 23 | 175 | 143 | **193** |
| **Purchase Expenses ($ Thousand)** | $ 1,730 | $ 11,109 | $ 13,187 | $ 16,653 | $ 13,019 | $ 8,550 | $ 8,703 | $ 85 | $ 355 | $ 654 | $ 5,919 | $ 4,566 | **$ 84,529** |
| **Average Purchase Price ($/MWh)** | $ 30.26 | $ 34.93 | $ 39.84 | $ 45.65 | $ 45.48 | $ 43.61 | $ 41.68 | $ 34.60 | $ 41.70 | $ 38.28 | $ 43.88 | $ 43.20 | **$ 50.00** |

**Balancing Purchases FY 2011**

| | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Monthly Hours** | 744 | 721 | 744 | 744 | 672 | 743 | 720 | 744 | 720 | 744 | 744 | 720 | **8,760** |
| **Balancing Purchases (aMW)** | 7 | 216 | 277 | 373 | 320 | 177 | 246 | 21 | 36 | 4 | 75 | 50 | **149** |
| **Purchase Expenses ($ Thousand)** | $ 240 | $ 8,751 | $ 11,180 | $ 14,772 | $ 11,714 | $ 7,941 | $ 9,761 | $ 626 | $ 1,145 | $ 131 | $ 2,812 | $ 1,606 | **$ 70,680** |
| **Average Purchase Price ($/MWh)** | $ 45.07 | $ 42.59 | $ 44.62 | $ 47.55 | $ 47.48 | $ 47.05 | $ 42.77 | $ 39.10 | $ 43.63 | $ 40.46 | $ 50.07 | $ 44.40 | **$ 54.11** |

## Table 4.8.3: Winter Hedging Purchases

**Winter Hegding Contract Purchases (MW Purchased on HLH ONLY)**

| FY | Nov | Dec | Jan | Feb | Mar | Apr |
|---|---|---|---|---|---|---|
| **2010** | 300 | 300 | 300 | 300 | 300 | 300 |
| **2011** | 300 | 300 | 300 | 300 | 300 | 300 |

**Winter Hedging Contracts Purchase Expense ($ Thousand)**

| FY | Nov | Dec | Jan | Feb | Mar | Apr | Total |
|---|---|---|---|---|---|---|---|
| **2010** | $ 6,811 | $ 7,379 | $ 7,095 | $ 6,811 | $ 7,663 | $ 7,379 | **$ 43,138** |
| **2011** | $ 7,095 | $ 7,379 | $ 7,095 | $ 6,811 | $ 7,663 | $ 7,379 | **$ 43,421** |

**Table 4.8.4 Augmentation Power Purchases**

**Price = Weighted average annual purchase price for 1937 from 70 WY run.**

| FY | MW | Hours | $/MWh | Exp. ($ Thousand) |
|---|---|---|---|---|
| **2010** | 476 | 8760 | 42.74 | $ 178,100 |
| **2011** | 680 | 8760 | 45.48 | $ 271,045 |
| **2012** | 501 | 8784 | 48.08 | $ 211,656 |
| **2013** | 699 | 8760 | 50.77 | $ 310,848 |
| **2014** | 669 | 8760 | 52.56 | $ 308,232 |
| **2015** | 865 | 8760 | 54.80 | $ 415,263 |
| | | | **Average** | **$ 282,524** |

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## Chapter 5: Excerpts from Customer ASC Reports

**Avista Utilities**
**Franklin PUD**
**Idaho Power Company**
**NorthWestern Energy**
**PacifiCorp**
**Portland General Electric**
**Puget Sound Energy**
**Snohomish County PUD**

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# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

## AVISTA UTILITIES

July 2009

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# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## Avista Utilities

Docket Number: ASC-10-AV-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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## TABLE OF CONTENTS

**List of Tables**

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## 1. FILING DATA

Utility: **Avista Utilities**
1411 E. Mission Ave.
Spokane, WA 99252-0001
http://www.avistautilities.com/residential/pages/default.aspx

Parties to the Filing:

Investor-Owned Utilities (IOUs):
Idaho Power Company (IPC)
NorthWestern Energy (NorthWestern or NWE)
PacifiCorp (PAC)
Portland General Electric (PGE)
Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
Franklin County PUD (Franklin)
Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
Idaho Public Utility Commission
Public Power Council
Public Utility Commission of Oregon (OPUC)
Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Avista's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

# 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Avista on October 15, 2008 (including errata, if applicable), and (2) the same information adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | October 15, 2008 As Filed | July 21, 2009 Final Report |
|---|---|---|
| Production Cost | $ 394,700,327 | $ 390,305,403 |
| Transmission Cost | $ 59,607,565 | $ 58,131,045 |
| (Less) NLSL Costs | $ 0 | $ 0 |
| Contract System Cost (CSC) | **$ 454,307,891** | **$ 448,436,447** |
| | | |
| Total Retail Load (MWh) | 8,924,726 | 8,924,726 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 8,924,726 | 8,924,726 |
| Distribution Losses | 452,964 | 452,964 |
| Contract System Load (CSL) | **9,377,690** | **9,377,690** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$48.45/MWh** | **$47.82/MWh** |

## 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the mid-point of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Montana Riverbed** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 2008 | | | |
| Delta* | 0 | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Montana Riverbed** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | N/A | | | |
| Delta* | 0 | | | |

*The Delta is the incremental change in the ASC as new resources come on-line.
Avista did not complete a materiality test. BPA completed the calculation and determined the Montana Riverbed Lease 2008 value did not meet the minimum materiality threshold of 2.5 percent. *See* Section 5.9 for details.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Lancaster** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 2010 | | | |
| Delta* | -2.50 | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Lancaster/ Montana Riverbed** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 2010 | | | |
| Delta* | 3.19 | | | |

*The Delta is the incremental change in the ASC as the new resources come on line. Lancaster power purchase agreement meets the minimum 2.5 percent materiality threshold. In addition, Montana Riverbed Lease will be grouped with Lancaster as a major new resource. *See* Section 5.8 for details.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010-2011 | 49.51 | 44.61 |

# 3. FILING REQUIREMENTS

## 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## FRANKLIN COUNTY PUD

July 2009

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# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

# Public Utility District No. 1
# of Franklin County

Docket Number: ASC-10-FR-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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## TABLE OF CONTENTS

**Section** **Page**

**List of Tables**

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## 1. FILING DATA

Utility: **Public Utility District No. 1 of Franklin County**
1411 W. Clark Street,
Pasco, WA 99301
http://www.franklinpud.com/

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer Owned Utilities (COUs):
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Year: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Public Utility District No. 1 of Franklin County's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

## 2. AVERAGE SYSTEM COST SUMMARY

### 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and the most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Franklin on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | October 15, 2008 As Filed | July 21, 2009 Final Report |
|---|---|---|
| Production Cost | $44,996,444 | $44,845,428 |
| Transmission Cost | $ 333,260 | $300,363 |
| (Less) NLSL Costs | $0 | $0 |
| Contract System Cost (CSC) | **$45,329,704** | **$45,145,790** |
| | | |
| Total Retail Load (MWh) | 886,305 | 886,305 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 886,305 | 886,305 |
| Distribution Losses | 41,443 | 41,443 |
| Contract System Load (CSL) | **927,748** | **927,748** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$48.86/MWh** | **$48.66/MWh** |

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. Franklin did not submit information on new resources.

**Table 2.2.1: New Resource Additions Coming On-Line**
**Prior to Exchange Period ($/MWh)**

| **As-Filed FY 2010-2011 Exchange Period ASC** | |
|---|---|
| **Resource** | **N.A.** |
| Expected On-Line Date | |
| Delta* | |

| **Final Report FY 2010-2011 Exchange Period ASC** | |
|---|---|
| **Resource** | **Pipeline Contract** |
| Expected On-Line Date | 01/01/08 |
| Delta* | (1.47) |

*The Delta is the incremental change in the ASC as new resources come on line.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **N.A.** |
| Expected On-Line Date | |
| Delta* | |

| Final Report FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **N.A.** |
| Expected On-Line Date | |
| Delta* | |

*The Delta is the incremental change in the ASC as new resources come on line.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010- 2011 | 46.15 | 49.28 |

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## IDAHO POWER COMPANY

July 2009

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## Idaho Power Company

Docket Number: ASC-10-IP-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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## TABLE OF CONTENTS

**List of Tables**

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## 1. FILING DATA

Utility: **Idaho Power Company (IPC)**
1221 W. Idaho St.
Boise, ID 83702
http://www.idahopower.com/default.cfm

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Utilities (Avista)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine IPC's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

# 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and most recent Annual Reports, including the most recent Cost of Service Analysis (COSA), for COUs. The submitted information includes the "Appendix 1," an Excel-based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by IPC on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | October 15, 2008 As Filed | July 21, 2009 Final Report |
|---|---|---|
| Production Cost | $ 461,275,498 | $ 461,434,297 |
| Transmission Cost | $ 104,444,121 | $ 95,664,101 |
| (Less) NLSL Costs | ($ 20,611,958) | ($ 25,276,624) |
| Contract System Cost (CSC) | **$ 545,107,660** | **$ 531,821,775** |
| | | |
| Total Retail Load (MWh) | 14,541,825 | 14,541,825 |
| (Less) NLSL | (385,400) | (385,400) |
| Total Retail Load (Net of NLSL) | 14,156,425 | 14,156,425 |
| Distribution Losses | 1,003,386 | 1,003,386 |
| Contract System Load (CSL) | **15,159,811** | **15,159,811** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$ 35.96/MWh** | **$ 35.08/MWh** |

## 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the mid-point of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Danskin** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | March 2008 | | | |
| Delta* | 0.71 | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Danskin** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | March 2008 | | | |
| Delta* | 0 | | | |

*The Delta is the incremental change in the ASC as new resources come on line. Danskin did not meet the materiality threshold. *See* Section 5.6 for additional details.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **N/A** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | | | | |
| Delta* | | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **N/A** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | | | | |
| Delta* | | | | |

*The Delta is the incremental change in the ASC as new resources come on line.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh)**
**Prior to New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010-2011 | 39.19 | 35.65 |

# 3. FILING REQUIREMENTS

## 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings. Subsequent REP Settlement Agreements with BPA's investor-owned utility customers

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## NORTHWESTERN ENERGY

July 2009

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# FY 2010 – FY 2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## NorthWestern Energy

Docket Number: ASC-10-NW-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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## TABLE OF CONTENTS

**List of Tables**

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## 1. FILING DATA

Utility: **NorthWestern Energy**
40 E. Broadway
Butte, MT 59701
www.NorthWesternEnergy.com

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- Portland General Electric (PGE)
- PacifiCorp (PAC)
- Puget Sound Energy (PSE)

Consumer Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine NorthWestern Energy's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

## 2. AVERAGE SYSTEM COST SUMMARY

### 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and the most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by NWE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | **October 15, 2008 As Filed** | **July 21, 2009 Final Report** |
|---|---:|---:|
| Production Cost | $337,095,343 | $342,080,537 |
| Transmission Cost | $31,980,992 | $30,083,720 |
| (Less) NLSL Costs | $0 | $0 |
| Contract System Cost (CSC) | **$369,076,335** | **$372,164,257** |
| | | |
| Total Retail Load (MWh) | 5,863,531 | 5,863,531 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 5,863,531 | 5,863,531 |
| Distribution Losses | 257,995 | 257,995 |
| Contract System Load (CSL) | **6,121,526** | **6,121,526** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$60.29/MWh** | **$60.80/MWh** |

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December, 31, 2007) to the end of the Exchange Period (September, 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including in response to comments submitted by the utility and/or intervenors during the ASC Review Process. NWE did not submit information on new resources.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **NA.** |
| Expected On-Line Date | |
| Delta* | |

| Final Report FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **NA.** |
| Expected On-Line Date | |
| Delta* | |

*The Delta is the incremental change in the ASC as new resources come on line.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **NA.** |
| Expected On-Line Date | |
| Delta* | |

| Final Report FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **NA.** |
| Expected On-Line Date | |
| Delta* | |

*The Delta is the incremental change in the ASC as new resources come on line.

### 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, and adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to the New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010- 2011 | 55.30 | 57.57 |

## 3. FILING REQUIREMENTS

### 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. § 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## PACIFICORP

July 2009

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# FY 2010 – FY 2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## PacifiCorp

Docket Number: ASC-10-PA-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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**TABLE OF CONTENTS**

**Section** **Page**

**List of Tables**

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## 1. FILING DATA

Utility: **PacifiCorp**
825 NE Multnomah
Portland, OR 97232
http://www.pacificorp.com

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PAC's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This Final FY 2010-2011 Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

# 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel-based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by PAC on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | October 15, 2008 As Filed | July 21, 2009 Final Report |
|---|---|---|
| Production Cost | $946,472,681 | $946,500,846 |
| Transmission Cost | $177,422,214 | $174,532,323 |
| (Less) NLSL Costs | $0 | $0 |
| Contract System Cost (CSC) | **$1,123,894,895** | **$1,121,033,170** |
| | | |
| Total Retail Load (MWh) | 21,476,886 | 21,476,886 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 21,476,886 | 21,476,886 |
| Distribution Losses | 575,581 | 575,581 |
| Contract System Load (CSL) | **22,052,467** | **22,052,467** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$50.96/MWh** | **$50.83/MWh** |

## 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the mid-point of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| **As-Filed FY 2010-2011 Exchange Period ASC** | | | | |
|---|---|---|---|---|
| **Resource** | **Group 1** | **Chehalis (525 MW)** | **Group 3** | **Group 4** |
| Expected On-Line Date | 08/01/08 | 10/01/08 | 04/01/09 | 04/01/09 |
| Delta* | 0.46 | -3.10 | 0.67 | 0.38 |

| **Final Report FY 2010-2011 Exchange Period ASC** | | | | |
|---|---|---|---|---|
| **Resource** | **Group A** | | | |
| Expected On-Line Date | 10/01/08 | | | |
| Delta* | 2.40 | | | |

*The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.1 of this report regarding regrouping.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **N/A** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | | | | |
| Delta* | | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Group B** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 10/01/10 | | | |
| Delta* | 1.80 | | | |

*The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.1 of this report regarding regrouping.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to the New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010 - 2011 | 51.40 | 54.80 |

# 3. FILING REQUIREMENTS

## 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## PORTLAND GENERAL ELECTRIC

July 2009

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# FY 2010 – 2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## Portland General Electric

Docket Number: ASC-10-PG-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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**TABLE OF CONTENTS**

**Section** **Page**

**List of Tables**

## 1. FILING DATA

Utility: **Portland General Electric (PGE)**
121 SW Salmon Street
Portland, Oregon 97201
http://www.portlandgeneral.com/

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PGE's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

# 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes PGE's CY 2007 Base Period ASC based on (1) the ASC information filed by PGE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | **October 15, 2008 As Filed** | **July 21, 2009 Final Report** |
|---|---|---|
| Production Cost | $905,934,811 | $951,698,149 |
| Transmission Cost | $116,700,294 | $111,726,269 |
| (Less) NLSL Costs | ($1,725,798) | $0 |
| Contract System Cost (CSC) | **$1,020,909,307** | **$1,063,424,418** |
| | | |
| Total Retail Load (MWh) | 17,461,742 | 17,461,742 |
| (Less) NLSL | (31,637) | 0 |
| Total Retail Load (Net of NLSL) | 17,430,105 | 17,461,742 |
| Distribution Losses | 942,875 | 942,875 |
| Contract System Load (CSL) | **18,372,980** | **18,404,617** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$55.57/MWh** | **$57.78/MWh** |

Note: PGE's NLSL adjustment would have increased PGE's ASC, which is not permitted by the ASCM. *See 2008 ASCM ROD at 93.*

## 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

PGE submitted information on new resources with its October 15, 2008, ASC filing. The Biglow Canyon III wind project is scheduled to come on-line in October of 2010. No other new resource information was submitted that showed any resources coming on-line during the Exchange Period.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **Group 1** |
| Expected On-Line Date | September 2009 |
| Delta* | 1.75 |

| Final Report FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **Group 1** |
| Expected On-Line Date | September 2009 |
| Delta* | 2.78 |

*The Delta is the incremental change in the ASC as new resources come on line. See Section 6.2 for details.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **Biglow Canyon III** |
| Expected On-Line Date | October 2010 |
| Delta* | 1.86 |

| Final Report FY 2010-2011 Exchange Period ASC | |
|---|---|
| **Resource** | **Biglow Canyon III** |
| Expected On-Line Date | October 2010 |
| Delta* | 2.64 |

*The Delta is the incremental change in the ASC as new resources come on line. See Section 6.2 for details.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource Additions**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010- 2011 | 59.51 | 55.57 |

# 3. FILING REQUIREMENTS

## 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## PUGET SOUND ENERGY

July 2009

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# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## Puget Sound Energy

Docket Number: ASC-10-PS-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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## TABLE OF CONTENTS

**Section** **Page**

## List of Tables

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## 1. FILING DATA

Utility: **Puget Sound Energy**
10885 NE 4th Street
P.O. Box 97034
Bellevue WA 98009-9734
http://www.pse.com

Parties to the Filing:

Investor Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)

Consumer Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:
Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PSE's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

## 2. AVERAGE SYSTEM COST SUMMARY

### 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by PSE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | **October 15, 2008 As Filed** | **July 21, 2009 Final Report** |
|---|---:|---:|
| Production Cost | $1,256,004,114 | $1,241,342,190 |
| Transmission Cost | $107,712,563 | $106,415,114 |
| (Less) NLSL Costs | $0 | $0 |
| Contract System Cost (CSC) | **$1,363,716,676** | **$1,347,757,304** |
| | | |
| Total Retail Load (MWh) | 21,626,537 | 21,626,537 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 21,626,537 | 21,626,537 |
| Distribution Losses | 1,092,140 | 1,092,140 |
| Contract System Load (CSL) | **22,718,677** | **22,718,677** |
| | | |
| **CY 2007 Base Period ASC (CSC / CSL)** | **$60.03/MWh** | **$59.32/MWh** |

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| **As-Filed FY 2010-2011 Exchange Period ASC** | | | | |
|---|---|---|---|---|
| **Resource** | **Group 1** | | **N/A** | **N/A** |
| Expected On-Line Date | 12/01/08 | | | |
| Delta* | **2.62** | | | |

| **Final Report FY 2010-2011 Exchange Period ASC** | | | | |
|---|---|---|---|---|
| **Resource** | **Group 1** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 12/01/08 | | | |
| Delta* | **1.28** | | | |

*The Delta is the incremental change in the ASC as new resources come on-line. *See* Section 5.5.3 of this report.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Group 2** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 10/01/10 | | | |
| Delta* | **2.41** | | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Group 2** | **N/A** | **N/A** | **N/A** |
| Expected On-Line Date | 10/01/10 | | | |
| Delta* | **4.65** | | | |

*The Delta is the incremental change in the ASC as new resources come on-line. *See* Section 5.5.2 of this report.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource**

| Date | October 15, 2008 As-Filed | July 21, 2009 Final Report |
|---|---|---|
| FY 2010- 2011 | 63.20 | 56.98 |

# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

## SNOHOMISH COUNTY PUD

July 2009

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# FY 2010-2011

# FINAL
# AVERAGE SYSTEM COST REPORT

**FOR**

## Snohomish County Public Utility District

Docket Number: ASC-10-SN-01
Effective Date: October 1, 2009

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 21, 2009

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**TABLE OF CONTENTS**

**Section** **Page**

## List of Tables

## 1. FILING DATA

Utility: **Snohomish County PUD**
2320 California Street
Everett, Washington 98201
http://www.snopud.com

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Utilities (Avista)
- Idaho Power Company (IPC)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
- Franklin County PUD (Franklin)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Snohomish's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

## 2. AVERAGE SYSTEM COST SUMMARY

### 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Snohomish on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC**
*(Results of Appendix 1 calculations)*

| | October 15, 2008 As Filed | July 21, 2009 Final Report |
|---|---|---|
| Production Cost | $269,400,580 | $269,544,820 |
| Transmission Cost | $30,449,717 | $30,330,696 |
| (Less) NLSL Costs | $0 | $0 |
| Contract System Cost (CSC) | **$299,850,297** | **$299,875,515** |
| | | |
| Total Retail Load (MWh) | 6,774,641 | 6,774,641 |
| (Less) NLSL | 0 | 0 |
| Total Retail Load (Net of NLSL) | 6,774,641 | 6,774,641 |
| Distribution Losses | 338,732 | 247,274 |
| Contract System Load (CSL) | **7,113,373** | **7,021,916** |
| | | |
| **CY 2007 Base Period ASC (CSC/CSL)** | **$42.15/MWh** | **$42.71/MWh** |

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the mid-point of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) ) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

**Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **N/A** | **Resource #1** | **Resource #2** | **N/A** |
| Expected On-Line Date | | 10/01/08 | 03/01/09 | |
| Delta* | | 0.25 | 2.41 | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | **Enron** | **Group A** | | **N/A** |
| Expected On-Line Date | 01/01/08 | 03/01/09 | | |
| Delta* | -2.48 | 4.09 | | |

*The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.3 of this report regarding regrouping.

**Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)**

| As-Filed FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | Resource #3 | Resource #4 | **N/A** | **N/A** |
| Expected On-Line Date | 10/01/10 | 10/01/10 | | |
| Delta* | 3.87 | 0.25 | | |

| Final Report FY 2010-2011 Exchange Period ASC | | | | |
|---|---|---|---|---|
| **Resource** | Morgan Stanley | | **N/A** | **N/A** |
| Expected On-Line Date | 10/01/10 | | | |
| Delta* | -1.76 | | | |

*The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.3 of this report regarding regrouping.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

**Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource**

| Date | October 15, 2008 As-Filed | July 21, 2009 Draft Report |
|---|---|---|
| FY 2010 - 2011 | 46.96 | 47.67 |

# 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<br>(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.<br>Margin over Wholesale Cost of Power is $5,870/mo.<br><br>Total Industrial sales in 2004:  401,856 MWh<br>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.<br><br>Total annual MWh sales = 283,411 MWh.<br>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.

**Donations Proposal:** 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.

**Rate Credit Performance Requirements Proposal:** 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.

## Attachment 1

# 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.

[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.