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

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

Volume 1

September 2008

WP-07-FS-BPA-13A

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WHOLESALE POWER RATE DEVELOPMENT STUDY

DOCUMENTATION

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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning 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
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program

DROD	Draft Record of Decision
DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
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
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company

ISO	Independent System Operator
JP	Joint Party
JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members,

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis, and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

	Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool

MMBTU/MMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PS	Power Services
PDP	Proportional Draft Points

PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line

Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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1. INTRODUCTION

The Documentation for the 2007 Supplemental Wholesale Power Rate Development Study shows the details of the calculation of the proposed rates. It contains the source data, the calculations, and the results. There are 2 Volumes, the first containing Sections 1, 2, 3, 4 and the Appendices; the second containing Section 8. There are no sections 5, 6 and 7.

Section 1 contains an overview of the information used and developed in the various models used in the rate development process.

Section 2 contains the Description of the Ratemaking Tables, and the documentation of the Rate Analysis Model (RAM2007). The RAM2007 is a group of computer applications that performs most of the computations that determine BPA's proposed rates. The output tables of RAM2007 show the source data, calculations (in sequence), and the results (rate charges) of the rate development process.

Section 3 provides documentation of revenue forecasts for the rate test period of FY 2009 at both current and proposed rates and at current rates for the period immediately preceeding the one year rate test period.

Section 4 contains includes supporting data for rate calculations not performed in RAM2007 or revenue analyses. They include Generation Inputs for Ancillary Services and Other Services, Segmentation of Corps of Engineers/Bureau of Reclamation Transmission Facilities, Load Variance, Unauthorized Increase and Excess Factoring Documentation.

Section 8 contains the ASC forecast and supporting material, and is wholey contained in Volume 2.

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1. RATE PROCESS MODELING

The components listed below comprise 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.

Federal System Load Obligation Forecast
The Federal system load obligation forecast estimates the firm energy load obligations that BPA expects to serve under its firm requirements power sales contracts (PSCs) and other BPA contract obligations.

The Federal system firm requirements PSC obligation forecasts used in BPA's rate development process are the primary sources for: 1) allocation factors used to apportion costs; and 2) billing determinants used to calculate rates and revenues. These firm requirements PSC obligation forecasts are composed of customer group sales forecasts for consumer-owned utilities (COU), Federal agencies, direct service industrial customers (DSI), investor-owned utilities (IOU), and other BPA PSC obligations, such as the U.S. Bureau of Reclamation. The firm requirements PSC obligation forecasts are detailed in the FY 2009 Load Resource Study (WP-07-FS-BPA-09).

BPA also has contract obligations that are comprised of contracts other than those served under BPA's firm requirements PSC obligations. These "other contract obligations" include contract sales to utilities, marketers, and power commitments under the Columbia River Treaty. These obligations are also detailed in the FY 2009 Load Resource Study (WP-07-FS-BPA-09).

Hydro Regulation Study
BPA incorporates variables into its hydro regulation study that characterize project-by-project operating requirements, firm loads, firm resources, and markets for secondary energy, of which all affect the amount and timing of available hydro system generation. The hydro regulation study produces forecasts of the firm hydro generation available in each of 50 historical years, including critical water conditions for both the Federal system and PNW region. The Federal system hydro generation is used in the Federal system load resource balance and is detailed in the in the FY 2009 Load Resource Study (WP-07-FS-BPA-09). The Federal system 50-water year hydro generation tables are presented in the FY 2009 Risk Analysis Study (WP-07-FS-BPA-12). In addition, the hydro regulation study provides the PNW regional hydro data that is used for the secondary revenue analysis for the FY 2009 Market Price Forecast Study (WP-07-FS-BPA-11).

Federal System Load Resource Balance
The Federal system load resource balance completes BPA's loads and resources picture by comparing Federal system loads to Federal system resources. Federal system loads 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, 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 load resource balance. The surplus/deficit calculation is performed for each year of the rate test period and is detailed in the FY 2009 Load Resource Study, (WP-07-FS-BPA-09). Load Resource Study results are used as input into the FY 2009 Risk Analysis Study (WP-07-FS-BPA-12).

Revenue Requirement Study
The Revenue Requirement Study provides BPA's generation revenue requirement for the rate test period. The development process is explained in the FY 2009 Revenue Requirement Study (WP-07-FS-BPA-10). The revenue requirement is assigned to the resource pools for use in the Cost of Service Analysis of the WPRDS.

Secondary Energy Revenue Forecast (RiskMod)
The BPA Risk Analysis Model (RiskMod) is used to forecast the quantity of secondary energy available to sell and the amount of power purchases needed to meet firm loads (balancing purchases). RiskMod uses hydro generation available given 50 years of historical streamflow information (1929-1978). It computes the amount of Federal secondary energy available after serving firm loads and the amount of purchases needed to meet firm loads during monthly heavy and light load hour periods. RiskMod applies spot market prices supplied by the AURORA model to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. RiskMod is described in the FY 2009 Risk Analysis Study (WP-07-FS-BPA-12). RAM2007 and the Revenue Forecast Model both use the surplus energy revenues and power purchase expenses resulting from the secondary energy revenue forecast calculated in RiskMod.

The Market Price Forecast
The Market Price Forecast Study is used for four purposes in this rate case. The Market Price Forecast Study for the Supplemental Proposal is used for: (a) estimating the forward price for the DSI smelter payments for FY 2009; (b) estimating the uncertainty surrounding DSI smelter payments; (c) informing the secondary revenue forecast, and (d) providing a price input used for the risk analysis. For a complete description of the uncertainty surrounding payments to the DSI's, secondary revenue forecast and the risk analysis, *see* the FY 2009 Risk Analysis Study, WP-07-FS-BPA-12.

The tool used for the market price forecast is a model of the WECC power system called AURORA. AURORA is an economic fundamentals-based approach that models wholesale energy transactions in a competitive pricing system. AURORA uses a demand forecast and supply cost information to find an hourly market clearing price, or equivalently, the marginal cost. To determine price in a given hour, AURORA models the dispatch of electric generating resources in a least cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource. Over time, AURORA will add new resources and retire old resources based on the net present value of the resource.

Rate Analysis Model (RAM2007)
RAM2007 has three main steps: a Cost of Service Analysis Step (COSA), a Rate Design Step, and a Slice Separation Step that perform the calculations necessary to develop BPA's wholesale power rates.

1. RAM2007 Cost of Service Analysis Step. This step follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, residential exchange resources, and new resources) used to serve sales load and then allocating those costs to the rate pools (PF, IP, and NR).
2. RAM2007 Rate Design. After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in section 7(b) and section 7(c) of the Act. RAM2007 performs these rate adjustments including the 7(b)(2) rate test in its Rate Design Step.
3. RAM2007 Slice Separation Step. In the Rate Design Step, costs were allocated to the various rate pools, including the PF Preference rate pool that contained all firm PF Preference load. The Slice Separation Step separates out the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool, leaving 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. In addition, an adjustment to the costs allocated to the non-Slice product PF Preference pool is made is the Administrator decided to amortize part of the Lookback Amount in the rate period, and/or if there is an exchanging utility that is working off their deemer balance during the rate period.

Revenue and Purchased Power Expense Forecast
The Revenue Forecast documents the revenues at both current and proposed rates by applying those rates (IP, PF, and RL) to projected DSI, public and IOU billing determinants. The Revenue Forecast is used outside the rate-setting process with rates and loads as specified input. The Revenue Forecast does not include revenues from Transmission rates applicable to the power customers, unless those revenues are forecast to be collected by Power Services. The Revenue Forecast uses outputs from a number of sources to determine total revenues expected. The forecast uses output from RiskMod to obtain short-term marketing revenues, purchased power expenses, and 4(h)(10)(c) credits. Revenues from ancillary products and services and long-term contracts are an input to the Revenue Forecast, also.

Risk Analysis
The RiskMod and NORM models are used to quantify BPA's net revenue risk. RiskMod estimates net revenue variability associated with various economic, load, and generation resource capability variations. The NORM model estimates the non-operational risks, *i.e.*, those 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

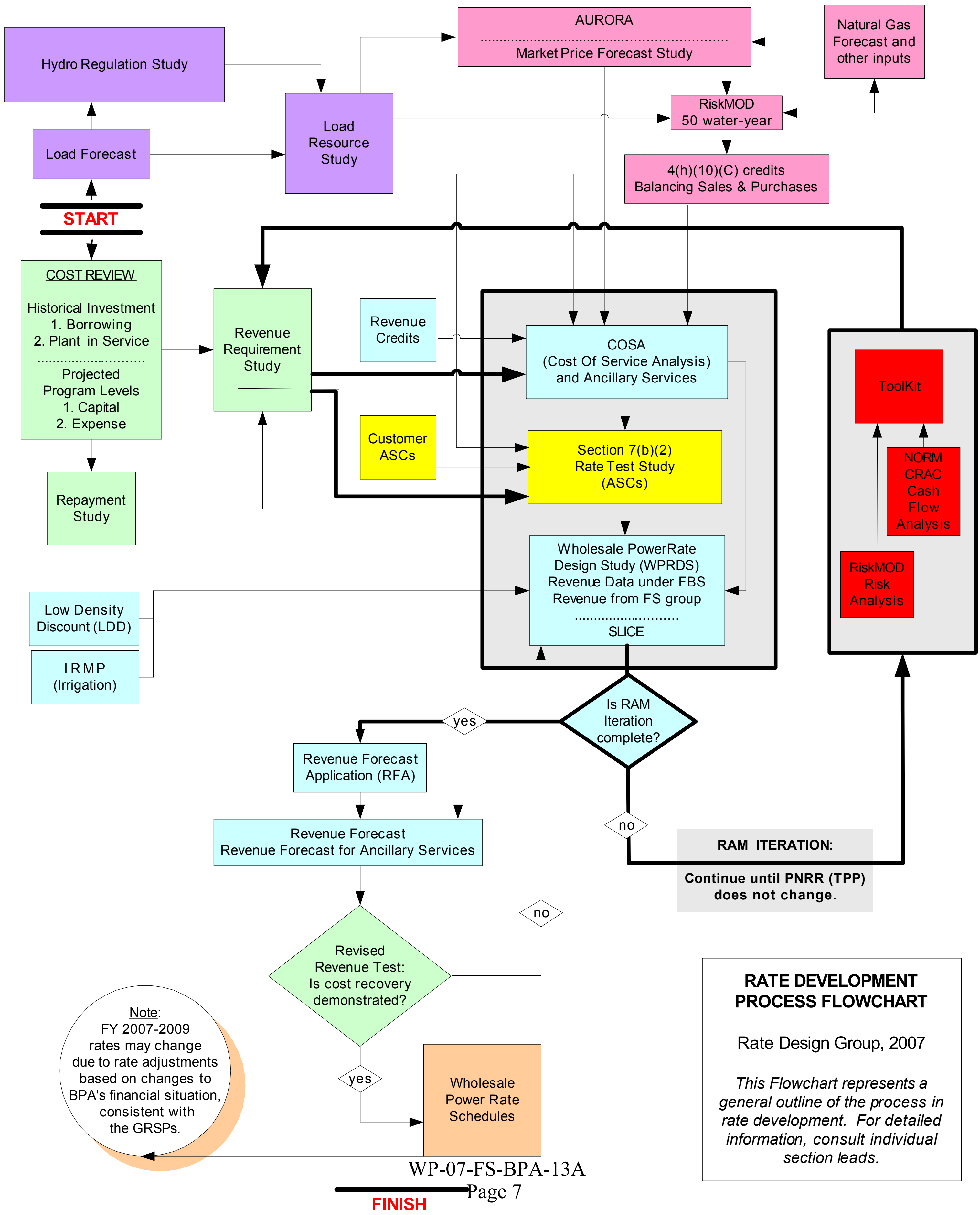
probability of making all scheduled Treasury payments on time and in full. (FY 2009 Risk Analysis Study, WP-07-FS-BPA-12).

Toolkit
The ToolKit Model is used to determine the probability of making all planned Treasury payments during the one-year rate period given the risks identified in Risk Analysis Model (RiskMod) and NORM, and the risk mitigation tools. The ToolKit is used to demonstrate BPA's ability to meet the one-year, 97.5 percent TPP standard, 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 generation. (*See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12).

2008 Average System Cost (ASC) Forecasts
BPA uses the 2008 ASC Cookbook model to estimate the ASCs of six IOUs and three COUs. BPA revised the ASC Cookbook to incorporate the proposed 2008 ASC Methodology. This model helps "functionalize," *i.e.*, assign costs to production, transmission, and distribution. Production costs and transmission costs are exchangeable; distribution costs are not. Using FERC Form 1s and annual reports as the primary data source, BPA estimated base year ASCs for the year 2006 using the proposed 2008 ASC Methodology. BPA then used the ASC Forecast Model to forecast the base ASCs through year 2013. The ASC Forecast Model uses various escalation factors and decision rules regarding surplus sales revenues and purchased power to calculate forecasted ASCs.

Other Analyses
In addition to the above mentioned programs and models, BPA also uses other analyses to calculate inputs used in the rate setting process. The Low Density Discount calculates the revenue impact of granting this discount.

RATE DEVELOPMENT PROCESS FLOWCHART



RATE DEVELOPMENT PROCESS FLOWCHART

Rate Design Group, 2007

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 FY2009 and Non-Slice PF Load Forecast, FY2009.
Gigawatthour (GWh) energy sales and peak kilowatt (kW)/mo. demand amounts for each month of the Rate Test Period FY 2009.

Table 2.2 (Sales_02)
Total PF Exchange Load Forecast, FY2009.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009.

Table 2.2 (Sales_03)
Total IP Load Forecast, FY2009.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009. (Note: No direct sale to the Direct Service Industry customers 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 2.2 (Sales_04)
Total NR Load Forecast, FY2009.
GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2009. (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 FY2009)
Itemized Revenue Requirement, FY2009.
Power Business Line (PBL) revenue requirements for the fiscal year 2009 rate test period.

Table 2.3.2 (COSA_07)
Functionalization of Residential Exchange Costs, FY2009.
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 2.3.3 (COSA_08)
Classified Revenue Requirement, FY2009.
Generation costs are classified between energy, demand, and load variance. All costs move through the COSA into the Rate Design Step of the RAM. Demand charge and load variance charge revenues are applied to the generation revenue requirement during the calculation of energy charges.

Table 2.3.4 (COSA_09)
Functionalized Revenue Credits, FY2009.
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 2.3.5 (COSA_09A)
Allocation of EE Revenue Credits to Conservation Costs, FY2009.
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 2.3.6 (COSA_09B)
Allocation of Deemer Credit to BPA Program Costs, FY2009.
The deemer credit that is due to Avista's deemer balance is credited to BPA Programs and the credit is allocated to all load pools.

Table 2.4.1 (ALLOCATE 01)
Energy Allocation Factors with Residential Exchange Included, FY2009.
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, FY2009.
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, FY2009.
Table calculates BPA's Average Cost of Nonfirm Energy.

Description of Ratemaking Tables

Table 2.5.2 (RDS_06)
Bonneville Average System Cost, FY2009.
Table calculates BPA's Average System Cost (BASC) and shows the PPL-90 Settlement Bonneville Average System Cost (mills/kwh). This BASC reflects the terms of a settlement agreement executed between BPA and PacifiCorp. It is based on the WP-07 rate case record as of May of 2007. This BASC will be used as an input into the PacifiCorp PPL-90 Capacity Rate formula for FY 2009.

Table 2.5.3 (RDS_11)
Allocation of Secondary Revenues and Other Revenue Credits, FY2009.
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, FY2009.
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, FY2009.
Table summarizes the allocations from Tables ALLOCATE 02, RDS 11, and RDS 17, as well as allocates Low Density Discount and Irrigation Rate Mitigation costs to the PF Preference rate pool.

Table 2.5.6 (RDS_21)
7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta, FY2009.
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, FY2009.
The IP-83 rates are applied to the current DSI test period billing determinants to determine an average rate. Adjustments are made for Transmission, Exchange Cost, and Deferral to yield the DSI floor rate.

Table 2.5.8 (RDS_24)
Industrial Firm Power Floor Rate Test, FY2009.
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, FY2009.
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, FY2009.
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, FY2009.
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.

Description of Ratemaking Tables

Table 2.6.1 (SLICESEP_01)
Slice PF Product Separation, FY2009.
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.

Table 2.6.2 (SLICESEP_01)
After Slice Separation Step 7(c)(2) Delta Calculation, FY2009.
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 2009)
Calculation of Priority Firm Preference Rate Components, FY2009.
Table calculates Priority Firm Preference rates. Marginal cost rates are scaled to produce rates that recover costs allocated to PF Preference energy. The demand charges are identical for all rate pools.

Table 2.8 (Unbifurcated PF 2009)
Calculation of Unbifurcated Priority Firm Rate Components, FY2009.
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, FY2009.
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.

Description of Ratemaking Tables

Table 2.9A (Average PFx 2009)
Calculation of Average Priority Firm Exchange Rate Components, FY2009.
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.

Table 2.10 (IP 2009)
Calculation of Industrial Firm Power Rate Components, FY2009.
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 2009)
Calculation of New Resource Rate Components, FY2009.
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 2009 Flat)
Flat Priority Firm Rate Calculation, FY2009.
Table calculates the average annual flat Priority Firm Preference rate. The PF Preference energy and demand rates are applied to a flat load to determine an average annual flat PF Preference rate.

Table 2.13 (Slice Costing Table)
Slice Product Pricing, FY2009.
Table shows the costs and revenue credits associated with the PF Slice Product and calculates a cost per month per Slice Product percent.

Table 2.1

Sales 01

Total PF Load Forecast FY2009
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2009	HLH	3,052	3,240	3,708	3,535	3,186	3,312	2,948	2,867	3,091	3,114	3,114	2,811	63,123	7,206
	LLH	1,883	2,300	2,448	2,371	2,095	2,175	1,887	1,999	1,937	2,116	2,006	1,928		
	Demand	8,854	9,827	10,160	10,111	10,065	9,305	8,245	7,671	7,951	8,117	7,785	7,517		

Non-Slice PF Load Forecast FY2009
GWh Energy Sales

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2009	HLH	2,308	2,477	2,907	2,922	2,598	2,619	2,293	2,172	2,200	2,325	2,370	2,176	48,814	5,572
	LLH	1,424	1,758	1,920	1,960	1,708	1,720	1,467	1,514	1,379	1,580	1,527	1,493		
	Demand	6,694	7,512	7,966	8,358	8,206	7,359	6,412	5,810	5,659	6,061	5,925	5,819		

Table 2.2

Sales 02

		Total PF Exchange Load Forecast FY2009 GWh Energy Sales												Total Energy GWh	aMW
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	1,625	1,841	2,358	2,606	2,401	2,302	2,144	1,355	1,182	1,156	1,509	1,828	35,477	4,050
	LLH	986	1,062	1,328	1,713	1,525	1,393	1,230	851	647	657	759	1,019		
	Demand	5,388	5,688	7,179	8,143	7,444	5,789	5,801	3,794	3,352	3,833	4,456	5,381		

Sales 03

		Total IP Load Forecast FY2009 GWh Energy Sales												Total Energy GWh	aMW
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	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		

Sales 04

		Total NR Load Forecast FY2009 GWh Energy Sales												Total Energy GWh	aMW
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
	LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
	Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		

Table 2.3.1

COSA 06 - FY2009

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2009

($ 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	5,345,120	138,413	0	411,799	550,212
4. BPA FISH & WILDLIFE PROGRAM	176,547	4,572	0	231,929	236,501
5. TROJAN				2,500	2,500
6. WNP #1				169,746	169,746
7. WNP #2				518,334	518,334
8. WNP #3				150,817	150,817
9. SYSTEM AUGMENTATION				161,123	161,123
10. BALANCING POWER PURCHASES				74,835	74,835
11. TOTAL FEDERAL BASE SYSTEM	5,521,667	142,985	0	1,721,083	1,864,068
12. NEW RESOURCES					
13. IDAHO FALLS				6,436	6,436
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				61,483	61,483
16. TOTAL NEW RESOURCES				82,008	82,008
17. RESIDENTIAL EXCHANGE				1,955,586	1,955,586
18. CONSERVATION		17,166	0	157,322	174,488
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,824	694	0	189,006	189,700
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,824	694	0	189,006	189,700
23. TOTAL GENERATION COSTS	5,548,491	160,845	0	4,105,005	4,265,850
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				123,728	123,728
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,000	1,000
27. GENERAL TRANSFER AGREEMENTS				50,370	50,370
28. TOTAL TRANSMISSION COSTS				175,098	175,098
29. TOTAL PBL REVENUE REQUIREMENT		160,845	0	4,280,103	4,440,948
30. BPA TRANSMISSION REVENUE REQUIREMENT		165,152	31,335	448,084	644,571

Table 2.3.2

COSA 07

Functionalization of Residential Exchange Costs:

	($ Thousands)
Gross Residential Exchange Cost	$ 1,953,586
Residential Exchange Transmission	$ 151,134
Functionalized Residential Exchange Costs	$ 1,802,452

Table 2.3.3

COSA 08

COST OF SERVICE ANALYSIS
Classified Revenue Requirement
Test Period October 2008 - September 2009

($ 000)

	Total Revenue Requirement	Energy		Demand		Load Variance	
		Percent	Total	Percent	Total	Percent	Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 550,212	92.74%	$ 510,286	6.21%	$ 34,164	1.05%	$ 5,762
4. BPA FISH & WILDLIFE PROGRAM	$ 236,501	93.79%	$ 221,816	6.21%	$ 14,685		
5. TROJAN	$ 2,500	93.79%	$ 2,345	6.21%	$ 155		
6. WNP #1	$ 169,746	93.79%	$ 159,206	6.21%	$ 10,540		
7. WNP #2	$ 518,334	92.74%	$ 480,721	6.21%	$ 32,185	1.05%	$ 5,428
8. WNP #3	$ 150,817	93.79%	$ 141,452	6.21%	$ 9,365		
9. SYSTEM AUGMENTATION	$ 161,123	92.74%	$ 149,431	6.21%	$ 10,005	1.05%	$ 1,687
10. BALANCING POWER PURCHASES	$ 74,835	92.74%	$ 69,404	6.21%	$ 4,647	1.05%	$ 784
11. TOTAL FEDERAL BASE SYSTEM	$ 1,864,068		$ 1,734,663		$ 115,745		$ 13,660
12. NEW RESOURCES							
13. IDAHO FALLS	$ 6,436				$ 400		$ 67
14. COWLITZ FALLS	$ 14,089	92.74%	$ 13,067	6.21%	$ 875	1.05%	$ 148
15. OTHER NEW RESOURCES PURCHASES	$ 61,483	92.74%	$ 57,022	6.21%	$ 3,818	1.05%	$ 644
16. TOTAL NEW RESOURCES	$ 82,008		$ 70,088		$ 5,092		$ 859
17. RESIDENTIAL EXCHANGE	$ 1,802,452	100.00%	$ 1,802,452				
18. CONSERVATION	$ 174,488	93.79%	$ 163,654	6.21%	$ 10,834		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 189,700	92.74%	$ 175,935	6.21%	$ 11,779	1.05%	$ 1,986
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 189,700		$ 175,935		$ 11,779		$ 1,986
23. TOTAL GENERATION COSTS	$ 4,112,716		$ 3,952,761		$ 143,450		$ 16,506
24. TRANSMISSION COSTS:							
25. TBL TRANSMISSION/ANCILLARY SERV	123,728	100.00%	$ 123,728				
26. 3RD PARTY TRANS/ANCILLARY SERVI	1,000	100.00%	$ 1,000				
27. GENERAL TRANSFER AGREEMENTS	50,370	100.00%	$ 50,370				
28. TOTAL TRANSMISSION COSTS	175,098		175,098				
29. TOTAL PBL REVENUE REQUIREMENT	$ 4,287,814		$ 4,127,859		$ 159,956		

Table 2.3.4

COSA 09

COST OF SERVICE ANALYSIS
Functionalized Revenue Credits
Test Period October 2008 - September 2009

		FY 2009 ($ 000)
Colville Credit	$	4,600
'4(h)(10)(c)	$	88,480
Ancillary and Reserve Service Revs.	$	79,306
Reserve Product Revenue	$	3,630
Downstream Benefits & Storage	$	8,921
Network Wind Integration&Shaping	$	1,933
Green Tags	$	2,799
Misc. Revenues	$	3,420
Totals	$	193,087

Table 2.3.5

COSA 09A

COST OF SERVICE ANALYSIS
Allocation of EE Revenue Credits to Conservation Costs
Test Period October 2008 - September 2009

		FY 2009 ($ 000)
Conservation Expense Before EE Revenues	$	174,488
Energy Efficiency Revenues	$	(22,000)
Net Conservation Expense	$	152,488

Table 2.3.6

COSA 09B

COST OF SERVICE ANALYSIS
Allocation of Deemer Credit to BPA Program Costs
Test Period October 2008 - September 2009

		FY 2009
BPA Program Costs Before Deemer Credit	$	364,798
Deemer Credit	$	(16,530)
Net BPA Program Costs	$	348,268

Table 2.4.1

ALLOCATE 01

Energy Allocation Factors with Residential Exchange Included
Average Megawatts

	2009
Federal Base System	
Total Usage	
Priority Firm..............................	11,582
Industrial Firm...........................	0.0001
New Resource Firm...................	0.0001
Surplus Firm Other....................	640
Total..	12,223
Federal Base System	
Priority Firm..............................	7,916
Industrial Firm...........................	0.00
New Resource Firm...................	0.00
Surplus Firm Other....................	0.00
Total..	7,916
Residential Exchange	
Priority Firm..............................	3,666
Industrial Firm...........................	0.00
New Resource Firm...................	0.00
Surplus Firm Other....................	502
Total..	4,167
New Resource	
Priority Firm..............................	0
Industrial Firm...........................	0.00
New Resource Firm...................	0.00
Surplus Firm Other....................	142
Total..	142
Conservation	
Priority Firm..............................	11,582
Industrial Firm...........................	0.0001
New Resource Firm...................	0.0001
Surplus Firm Other....................	640
Total..	12,223

Table 2.4.2

ALLOCATE 02

Initial Rate Pool Cost Allocations

($ 000)

FY 2009

CLASSES OF SERVICE:

Priority Firm - Preference		
FBS	$	1,864,068
NR	$	-
Exchange	$	1,585,549
conservation	$	144,499
BPA programs	$	330,023
Total	$	3,924,138
Industrial Firm Power		
FBS	$	-
NR	$	0.013
Exchange	$	0.035
conservation	$	0.001
BPA programs	$	0.003
Total	$	0.052
New Resources Firm		
FBS	$	-
NR	$	0.013
Exchange	$	0.035
conservation	$	0.001
BPA programs	$	0.003
Total	$	0.052
Surplus Firm Power		
FBS	$	-
NR	$	82,008
Exchange	$	216,904
conservation	$	7,989
BPA programs	$	18,245
Total	$	325,146
Grand Total	**$**	**4,249,284**

Table 2.5.1

RDS 05

RATE DESIGN STUDY
Average Cost of Nonfirm Energy
Test Period October 2008 - September 2009

Generation Costs:		**($ 000)**
Federal Base System	$	1,864,068
New Resources	$	82,008
Exchange	$	1,955,586
Conservation and EE	$	174,488
BPA Programs	$	189,700
Total Generation Costs	$	4,265,850
Transmission Costs For Firm Power	$	471,410
Transmission Costs For Nonfirm Pwr	$	123,728
Total Costs	$	4,860,988
Firm Power Sales:		**(GWh)**
Priority Firm		98,601
Industrial Power/Variable Industrial		0.000876
New Resources		0.000876
Other Obligations		10,128
FPS Pre-Sub., Slice Block, Rate Mitigation Contract Sales		1,625
Total Firm		110,354
Projected Trading Flr Sales		17,869
Total Sales		128,223
Average Cost of Nonfirm (mills/kwh)		37.91

Table 2.5.2

RDS 06

RATE DESIGN STUDY
Bonneville Average System Cost (BASC)
Test Period October 2008 - September 2009

Revenue Requirement:		**($ Thousands)**
Cost of Service Analysis	$	5,085,519
Applicable Revenue Credits	$	(132,152)
Total	$	4,953,367
Sales:		**(GWh)**
Firm Power		110,354
Nonfirm Energy		17,869
Total		128,223
Bonneville Average System Cost (mills/kwh):		38.63
PPL-90 Settlement Bonneville Average System Cost (mills/kwh)		33.0 *

* This BASC reflects the terms of a settlement agreement executed between BPA and PacifiCorp. It is based on the WP-07 rate case record as of May of 2007. This BASC will be used as an input into the PacifiCorp PPL-90 Capacity Rate formula for FY 2009.

Table 2.5.3

RDS 11

Rate Design Study
Allocation of Secondary and Other Revenue Credits
Test Period October 2008 - September 2009

($ 000)

		FY 2009
Forecast of Secondary Revenues	**$**	**774,239**
7b3 Costs Allocated to Secondary Revenues	**$**	**(205,293)**
Secondary Revenues After 7b3 Allocation	**$**	**568,946**

Allocation of Secondary Revenues Credit		
Priority Firm..	$	(568,946)
Industrial Firm...	$	-
New Resource Firm..	$	-
Surplus Firm Other..	$	-
Total..	**$**	**(568,946)**

		FY 2009
Total Other Revenue Credits	**$**	**193,087**

Allocation of Other Revenue Credits		
Priority Firm..	$	(193,087)
Industrial Firm...	$	-
New Resource Firm..	$	-
Surplus Firm Other..	$	-
Total..	**$**	**(193,087)**

Table 2.5.4

RDS 17

Rate Design Study
Calculation of FPS (Surplus)/Shortfall
Test Period October 2008 - September 2009

($ 000)

FPS (Surplus)/Shortfall		**FY 2009**
Costs allocated to FPS contract sales	$	325,146
Expected Revenue from FPS contract sales	$	(83,106)
FPS Pre-Sub Contract Revenue	$	(41,165)
(Surplus)/Shortfall	**$**	**200,874**
Secondary Revenues allocated to FPS	$	-
Revenue Credits allocated to FPS	$	-
FPS (Surplus)/Shortfall	**$**	**200,874**

Rate Design Study
Allocation of FPS (Surplus)/Shortfall
Test Period October 2008 - September 2009

($ 000)

Allocation of FPS (Surplus)/Shortfall		**FY 2009**
Priority Firm..	$	200,874
Industrial Firm..	$	-
New Resource Firm..	$	-
Surplus Firm Other..	$	(200,874)
Total..	**$**	**-**

Table 2.5.5

RDS 19

Rate Design Study
Summary of Initial Cost Allocations
Test Period October 2008 - September 2009

($ 000)

		FY 2009
Allocation of Revenue Requirement		
Priority Firm..	$	3,924,138
Industrial Firm...	$	0.05225
New Resource Firm.................................	$	0.05225
Surplus Firm Other..................................	$	325,146
Total...	$	4,249,284
Allocation of Secondary Revenues Credit		
Priority Firm..	$	(568,946)
Industrial Firm...	$	-
New Resource Firm.................................	$	-
Surplus Firm Other..................................	$	-
Total...	$	(568,946)
Allocation of other Revenues Credits		
Priority Firm..	$	(193,087)
Industrial Firm...	$	-
New Resource Firm.................................	$	-
Surplus Firm Other..................................	$	-
Total...	$	(193,087)
Allocation of FPS (Surplus)/Shortfall		
Priority Firm..	$	200,874
Industrial Firm...	$	-
New Resource Firm.................................	$	-
Surplus Firm Other..................................	$	(200,874)
Total...	$	-

Low Density Discount Expenses.......		
Priority Firm..	$	24,860
Irrigation Rate Mitigation...................		
Priority Firm..	$	12,036

Initial Allocation to Rate Pools..........		
Priority Firm..	$	3,399,875
Industrial Firm...	$	0.05225
New Resource Firm.................................	$	0.05225
Surplus Firm Other..................................	$	124,271
Total...	$	3,524,147

Table 2.5.6

RDS 21

Rate Design Study
7(c)(2) Delta Calculation
Test Period October 2008 - September 2009

			FY 2009
1	IP Allocated Costs	$	0.0523
2	IP Revenues @ Net Margin	$	0.0005
3	adjustment	$	(0.0004)
4	IP Marginal Cost Rate Revenues	$	0.0463
5	PF Marginal Cost Rate Revenues	$	5,395,366
6	PF Allocated Energy Costs	$	3,399,875
7	Numerator: 1-2-3-((4/5)*6)		0.0229
8			
9	PF Allocation Factor for Delta		11,582
10	NR Allocation Factor for Delta		0.0001
11	Total Allocation Factors for Delta		11,582
12	Denominator: 1.0 + ((9/11)*(4/5))		1.0000
13			
14	DELTA: (Numerator / Denominator)		**0.0229**

Rate Design Study
7(c)(2) Delta allocation
Test Period October 2008 - September 2009

		FY 2009
IP-PF Link Allocations:.......................		
Priority Firm..	$	0.0229
Industrial Firm.......................................	$	(0.0229)
New Resource Firm...............................	$	0.0000
Surplus Firm Other................................	$	-
Total..	$	0.0000

Allocation to Rate Pools after Link....................................		
Priority Firm Preference........................	$	2,176,569
Priority Firm Exchange.........................	$	1,223,306
Industrial Firm.......................................	$	0.02932
New Resource Firm...............................	$	0.05225
Surplus Firm Other................................	$	124,271
Total..	$	3,524,147

Table 2.5.7

RDS 23

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Calculation
Test Period October 2008 - September 2009
($ 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]	0.000500	0.000700	0.000509	0.000367	0.001200	0.001
2	IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3	Revenue	0.002	0.002	0.007	0.004	0.009	0.025
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 2008 - September 2009
($ Thousands)

	A	B	C	D	E	F
	Unbundled Requirements Products	**Total Transmission**	**Total Generation Demand**	**Total Energy**	**TOTALS**	**Average Rate**
1 IP Billing Determinants				0.001		
2 Floor Rate (mills/kWh)				20.98		
3 Value of Reserves Credit (mills/kWh)						
4 Revenue at Floor Rate Less VOR Credit				0.018	0.018	20.98
5 IP Revenue Under Proposed Rates	0	0	0.002	0.028	0.031	34.82
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 2006 - September 2009

Section 7(b)(2) Rate Test Trigger **8.20**

	FY 2009
Total PF Preference Load (GWH)	63123
PF Preference Protection Amount	$ 517,612

Table 2.5.9A

RDS 31

Rate Design Study
Calculation of 7(b)(3) Protection Amount Allocation
Test Period October 2008 - September 2009

		FY 2009
7b2 Protection Allocation................................		
Priority Firm Preference....................................		$ (517,612)
Priority Firm Exchange.......................................		$ 312,318
Industrial Firm...		$ 0.0077
New Resource Firm...		$ 0.0077
Surplus Firm Other..		$ -
Reduction in Secondary Revenue Credit	1/	$ 205,293
Total...		$ -

	FY 2009
Allocation to Rate Pools after 7b2..................	
Priority Firm Preference....................................	$ 1,658,957
Priority Firm Exchange.......................................	$ 1,535,625
Industrial Firm...	$ 0.0370
New Resource Firm...	$ 0.0600
Surplus Firm Other..	$ 124,271
Total...	$ 3,318,854

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 2008 - September 2009

			FY 2009
1	IP Allocated Costs after 7c2 adjustment	$	0.02932
2	IP share of 7b2 adjustment	$	0.00771
3	Total IP revenue requirement	$	0.03704
4			
5	IP revenues at PF preference rate	$	0.02201
6	IP Revenues @ Net Margin	$	0.00050
7	IP share of 7b2 adjustment	$	0.00771
8	Total IP revenue requirement	$	0.03022
	DELTA: (3 - 8)	$	0.00682

		FY 2009
IP-PF Linc 2 Allocation..		
Priority Firm Preference...	$	-
Priority Firm Exchange...	$	0.0068
Industrial Firm..	$	(0.0068)
New Resource Firm..	$	-
Surplus Firm Other...	$	-
Total..	$	(0.0000)

Allocation to Rate Pools after IP-PF Linc 2........................		
Priority Firm Preference...	$	1,658,957
Priority Firm Exchange...	$	1,535,625
Industrial Firm..	$	0.03022
New Resource Firm..	$	0.05996
Surplus Firm Other...	$	124,271
Total..	$	3,318,854

Table 2.6.1

SLICESEP 01

Rate Design Study
Slice PF Product Separation
Test Period October 2008 - September 2009

		FY 2009
Slice Revenue requirement..	$	567,816
Slice Revenue Credits...	$	(46,778)
Net Slice PF Product Revenue Requirement	$	521,038
Slice Implementation Expenses	$	2,486
Amount to Allocate	$	521,038

Allocation of Slice Revenues...		
Priority Firm Preference...	$	(521,038)
Priority Firm Exchange...	$	-
Industrial Firm..	$	-
New Resource Firm..	$	-
Surplus Firm Other...	$	-
Total..	$	(521,038)

Slice Secondary Revenue Credit Adjustment	$	175,193
Priority Firm Preference...	$	175,193
Priority Firm Exchange...	$	-
Industrial Firm..	$	-
New Resource Firm..	$	-
Surplus Firm Other...	$	-
Total..	$	175,193

Allocation to Rate Pools after Slice Separation Step............................		
Priority Firm Preference...	$	1,313,112
Priority Firm Exchange...	$	1,535,625
Industrial Firm..	$	0.030
New Resource Firm..	$	0.060
Surplus Firm Other...	$	124,271
Total..	$	2,973,009

Table 2.6.2

SLICESEP 02

Rate Design Study
After Slice Separation 7(c)(2) Delta Calculation
Test Period October 2008 - September 2009

			FY 2009
1	IP Allocated Costs	$	0.05225
2	IP Revenues @ Net Margin	$	0.00050
3	adjustment	$	0.02912
4	IP Marginal Cost Rate Revenues	$	0.04630
5	PF Marginal Cost Rate Revenues	$	2,652,887
6	PF Allocated Energy Costs	$	1,313,112
7	Numerator: 1-2-3-((4/5)*6)	$	(0.00028)
8			
9	PF Allocation Factor for Delta		5,734
10	NR Allocation Factor for Delta		0.0001
11	Total Allocation Factors for Delta		5,734
12	Denominator: 1.0 + ((9/11)*(4/5))		1.000
13			
14	DELTA: (Numerator / Denominator)		(0.00028)

Rate Design Study
After Slice Separation 7(c)(2) Delta allocation
Test Period October 2008 - September 2009

		FY 2009
IP-PF Link 3 Allocations:....................		
Priority Firm..	$	(0.00028)
Industrial Firm.......................................	$	0.00028
New Resource Firm...............................	$	-
Surplus Firm Other................................	$	-
Total..	$	-

Allocation to Rate Pools after Link 3..................................		
Priority Firm Preference........................	$	1,313,112
Priority Firm Exchange..........................	$	1,535,625
Industrial Firm.......................................	$	0.03050
New Resource Firm...............................	$	0.05996
Surplus Firm Other................................	$	124,271
Total..	$	2,973,009

Table 2.7

PF 2009

Rate Design Study
Calculation of Priority Firm Preference Rate Components
Test Period October 2008 - September 2009

COMPROMISE PF PREFERENCE RATE SHAPE

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

LV Rate 0.53

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy		
HLH	2,308	2,477	2,907	2,922	2,598	2,619	2,293	2,172	2,200	2,325	2,370	2,176	48814	16271	1857
LLH	1,424	1,758	1,920	1,960	1,708	1,720	1,467	1,514	1,379	1,580	1,527	1,493			
Demand	6,694	7,512	7,966	8,358	8,206	7,359	6,412	5,810	5,659	6,061	5,925	5,819			
LV Billing Determinant													36007632		

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 77,926	$ 89,206	$ 109,288	$ 93,238	$ 84,667	$ 79,163	$ 65,048	$ 51,469	$ 47,191	$ 61,436	$ 73,334	$ 69,494	$ 1,333,238	$ 1,153,157	86.49%
LLH	$ 35,228	$ 46,189	$ 52,943	$ 45,230	$ 39,816	$ 38,105	$ 29,914	$ 24,795	$ 15,704	$ 30,554	$ 35,044	$ 38,255			
Demand	$ 14,795	$ 17,728	$ 19,755	$ 17,552	$ 17,562	$ 14,644	$ 11,990	$ 9,006	$ 8,035	$ 10,545	$ 12,087	$ 12,221	$ 165,919	$ 143,450	86.49%
LV Revenue													$ 19,084	$ 16,506	86.49%
													$ 1,518,240	$ 1,313,112	86.49%

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
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**
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												**0.460**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 67,404	$ 77,145	$ 94,519	$ 80,645	$ 73,236	$ 68,479	$ 56,266	$ 44,520	$ 40,811	$ 53,135	$ 63,427	$ 60,095	$ 1,153,138
LLH	$ 30,473	$ 39,947	$ 45,783	$ 39,116	$ 34,436	$ 32,964	$ 25,879	$ 21,450	$ 13,580	$ 26,430	$ 30,310	$ 33,091	
Demand	$ 12,786	$ 15,324	$ 17,046	$ 15,212	$ 15,182	$ 12,657	$ 10,387	$ 7,786	$ 6,960	$ 9,091	$ 10,428	$ 10,591	$ 143,450
LV Revenue													$ 16,564
													$ 1,313,152

Non-Slice PF Average Rate

Energy Costs	**$ 1,153,157**	**23.62**
Demand Costs	**$ 143,450**	**2.94**
Unbundled Cost	**$ 16,506**	**0.34**
Total	**$ 1,313,112**	**26.90**
Billing Determinants	**48814**	

PFx 2009

Table 2.8

Rate Design Study
Calculation of Unbifurcated Priority Firm Rate Components
Test Period October 2008 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

Unbifurcated PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	4,677	5,081	6,066	6,141	5,587	5,613	5,092	4,222	4,273	4,270	4,623	4,639	98,601
LLH	2,870	3,362	3,777	4,083	3,620	3,567	3,117	2,850	2,584	2,773	2,766	2,947	
Demand	14,242	15,515	17,339	18,254	17,509	15,094	14,046	11,465	11,303	11,950	12,241	12,898	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
Energy	$ 228,953	$ 271,351	$ 332,173	$ 290,191	$ 266,466	$ 248,748	$ 208,025	$ 146,739	$ 121,102	$ 166,439	$ 206,506	$ 223,695	$ 2,710,388	$ 3,097,376	114.28%
Demand	$ 27,203	$ 31,651	$ 37,105	$ 33,223	$ 32,391	$ 25,962	$ 22,755	$ 15,363	$ 13,902	$ 17,925	$ 21,544	$ 23,474	$ 302,499	$ 302,499	100.00%
Transmission Costs														$ -	
													$ 3,012,887	$ 3,399,875	

Unbifurcated PF

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy	**34.67**	**36.73**	**38.57**	**32.44**	**33.07**	**30.96**	**28.96**	**23.71**	**20.18**	**27.01**	**31.94**	**33.70**
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**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
Energy	$ 261,642	$ 310,095	$ 379,601	$ 331,624	$ 304,512	$ 284,264	$ 237,726	$ 167,690	$ 138,393	$ 190,203	$ 235,991	$ 255,634	$ 3,097,376
Demand	$ 27,203	$ 31,651	$ 37,105	$ 33,223	$ 32,391	$ 25,962	$ 22,755	$ 15,363	$ 13,902	$ 17,925	$ 21,544	$ 23,474	$ 302,499
Transmission Costs													$ -
													$ 3,399,875

Unbifurcated PF Rate

Energy Costs	$ 3,097,376	31.41
Demand Costs	$ 302,499	3.07
Unbundled Cost	$ -	0.00
Transmission Costs	$ -	0.00
Total	$ 3,399,875	34.48
Billing Determinants	$ 98,601	

Unbifurcated PF	34.48
Transmission Costs	4.26
Delivered Unbifurcated PF	**38.74**

Table 2.9

Rate Design Study
Calculation of Utility Specific Priority Firm Exchange Rates and Net REP Benefits **REP 1**
Test Period October 2008 - September 2009

	A	B	C	D	E	F	G	H	I	J	K
	Utility ASCs	Delivered Unbifurcated PF Rate	Exchange Load GWH	Preliminary Benefits at Unbifurcated PF Rate (A - B) * C	Percent of Preliminary Benefits	7b3 and 7c2 Allocation Using Percent of Benefits	Exchange Load GWH	Supplemental 7b3 Charge F / G	Delivered Unbifurcated PF Rate	Utility Specific PF Exchange Rate H + I	Utility Specific Exchange Benefits (A - J) * C
Avista	$ 50.28	$ 38.74	4152	$ 47,919	8.3%	$ 25,838	4152	$ 6.22	$ 38.74	$ 44.96	$ 22,091
Idaho Power	$ 33.86	$ 38.74	0	$ -	0.0%	$ -	0	$ -	$ 38.74	$ 38.74	$ -
Northwestern Energy PNWR	$ 54.84	$ 38.74	928	$ 14,945	2.6%	$ 8,058	928	$ 8.68	$ 38.74	$ 47.42	$ 6,888
Pacificorp	$ 51.27	$ 38.74	9621	$ 120,556	20.8%	$ 65,009	9621	$ 6.76	$ 38.74	$ 45.50	$ 55,515
Portland General	$ 55.61	$ 38.74	8562	$ 144,441	24.9%	$ 77,889	8562	$ 9.10	$ 38.74	$ 47.84	$ 66,527
Puget Sound Energy	$ 59.71	$ 38.74	11871	$ 248,928	43.0%	$ 134,231	11871	$ 11.31	$ 38.74	$ 50.05	$ 114,671
Centralia	$ 35.56	$ 38.74	0	$ -	0.0%	$ -	0	$ -	$ 38.74	$ 38.74	$ -
Franklin	$ 45.74	$ 38.74	343	$ 2,399	0.4%	$ 1,293	343	$ 3.77	$ 38.74	$ 42.51	$ 1,107
Snohomish	$ 38.08	$ 38.74	0	$ -	0.0%	$ -	0	$ -	$ 38.74	$ 38.74	$ -
Total/Average				$ 579,188	100%	$ 312,318	35477	$ 8.80		$ 47.55	

Table 2.9A

PFx 2007-09

Rate Design Study
Calculation of Average Priority Firm Exchange Rate Components
Test Period October 2008 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

PFx billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
HLH	1,625	1,841	2,358	2,606	2,401	2,302	2,144	1,355	1,182	1,156	1,509	1,828	35,477
LLH	986	1,062	1,328	1,713	1,525	1,393	1,230	851	647	657	759	1,019	
Demand	5,388	5,688	7,179	8,143	7,444	5,789	5,801	3,794	3,352	3,833	4,456	5,381	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
Energy	$ 79,293	$ 94,220	$ 125,257	$ 122,680	$ 113,790	$ 100,453	$ 85,912	$ 46,050	$ 32,730	$ 43,238	$ 64,107	$ 84,510	$ 992,240	$ 1,417,828	142.89%
Demand	$ 10,292	$ 11,603	$ 15,364	$ 14,820	$ 13,771	$ 9,957	$ 9,398	$ 5,083	$ 4,123	$ 5,750	$ 7,843	$ 9,793	$ 117,797	$ 117,797	100.00%
												Transmission Costs	$ 151,134	$ 151,134	100.00%
													$ 1,261,171	$ 1,686,759	

PF exchange rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
Energy	**43.38**	**46.37**	**48.56**	**40.59**	**41.42**	**38.85**	**36.38**	**29.83**	**25.56**	**34.09**	**40.39**	**42.41**
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**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
Energy	$ 113,303	$ 134,633	$ 178,982	$ 175,299	$ 162,596	$ 143,538	$ 122,761	$ 65,802	$ 46,768	$ 61,784	$ 91,603	$ 120,758	$ 1,417,828
Demand	$ 10,292	$ 11,603	$ 15,364	$ 14,820	$ 13,771	$ 9,957	$ 9,398	$ 5,083	$ 4,123	$ 5,750	$ 7,843	$ 9,793	$ 117,797
												Transmission Costs	$ 151,134
													$ 1,686,759

PF Exchange Average Rate

Energy Costs	$ 1,417,828	39.96
Demand Costs	$ 117,797	3.32
Unbundled Cost	$ -	0.00
Transmission Costs	$ 151,134	4.26
Total	$ 1,686,759	47.54
Billing Determinants	$ 35,477	

Table 2.10

IP 2009

Rate Design Study
Calculation of Industrial Firm Power Rate Components
Test Period October 2008 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

IP billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
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	0.001
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	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 0.001	$ 0.001	$ 0.002	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.023	$ 0.028	121.59%
LLH	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.000	$ 0.001	$ 0.001	$ 0.001			
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	$ 0.002	$ 0.002	100.00%
													$ 0.025	$ 0.031	

IP rates	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
HLH	**41.06**	**43.80**	**45.71**	**38.80**	**39.63**	**36.76**	**34.50**	**28.82**	**26.08**	**32.13**	**37.62**	**38.84**
LLH	**30.08**	**31.94**	**33.54**	**28.06**	**28.34**	**26.95**	**24.79**	**19.92**	**13.85**	**23.52**	**27.91**	**31.16**
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**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.002	$ 0.002	$ 0.028
LLH	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.000	$ 0.001	$ 0.001	$ 0.001	
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	$ 0.002
													$ 0.031

IP Average Rate

Energy Costs	$ 0.0284	32.45
Demand Costs	$ 0.0021	2.37
Unbundled Cost	$ -	0.00
Total	$ 0.0305	34.82
Non-Slice Billing Determinants	$ 0.0009	

Table 2.11

NR 2009

Rate Design Study
Calculation of New Resource Rate Components
Test Period October 2008 - September 2009

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	33.77	36.02	37.59	31.91	32.59	30.23	28.37	23.70	21.45	26.42	30.94	31.94
LLH	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63
MONTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82

NR billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy
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	0.001
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	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 0.001	$ 0.001	$ 0.002	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.023	$ 0.058	247.61%
LLH	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.000	$ 0.001	$ 0.001	$ 0.001			
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	$ 0.002	$ 0.002	100.00%
													$ 0.025	$ 0.060	

NR rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**83.62**	**89.19**	**93.08**	**79.01**	**80.70**	**74.85**	**70.25**	**58.68**	**53.11**	**65.42**	**76.61**	**79.09**
LLH	**61.26**	**65.05**	**68.29**	**57.15**	**57.72**	**54.87**	**50.49**	**40.56**	**28.20**	**47.89**	**56.83**	**63.46**
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**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 0.004	$ 0.003	$ 0.004	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.002	$ 0.002	$ 0.003	$ 0.003	$ 0.003	$ 0.058
LLH	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.002	$ 0.001	$ 0.001	$ 0.002	$ 0.002	$ 0.002	
Demand	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.002
													$ 0.060

NR Average Rate

Energy Costs	$ 0.058	66.08
Demand Costs	$ 0.002	2.37
Unbundled Cost	$ -	0.00
Total	$ 0.060	68.45
Non-Slice Billing Determinants	$ 0.001	

Table 2.12

PF 2009 Flat

Rate Design Study
Calculation of Flat Priority Firm Preference Rate
Test Period October 2008 - September 2009

PF Preference Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
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**
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**

Flat Load FY2007-09

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

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HLH	$ 935	$ 922	$ 988	$ 861	$ 823	$ 826	$ 756	$ 631	$ 571	$ 704	$ 846	$ 818	$ 15,177
LLH	$ 510	$ 556	$ 606	$ 491	$ 439	$ 462	$ 409	$ 354	$ 229	$ 418	$ 480	$ 541	
Demand	$ 143	$ 153	$ 161	$ 137	$ 139	$ 129	$ 122	$ 101	$ 92	$ 113	$ 132	$ 137	$ 1,556
													$ 16,733

Flat PF Preference Rate FY2007-09 $ 25.45

Table 2.13

Slice Costing Table

			FY 2009 forecast
1	**Operating Expenses**		
2	**Power System Generation Resources**		
3	**Operating Generation**		
4	COLUMBIA GENERATING STATION (WNP-2)	$	293,700
5	BUREAU OF RECLAMATION	$	82,100
6	CORPS OF ENGINEERS	$	179,500
7	LONG-TERM CONTRACT GENERATING PROJECTS	$	31,522
8	**Sub-Total**		
9	**Operating Generation Settlement Payment**		
10	COLVILLE GENERATION SETTLEMENT	$	20,909
11	SPOKANE GENERATION SETTLEMENT	$	-
12	**Sub-Total**		
13	**Non-Operating Generation**		
14	TROJAN DECOMISSIONING	$	2,500
15	WNP-1&3 DECOMISSIONING	$	400
16	**Sub-Total**		
17	**Contracted Power Purchases**		
18	PNCA HEADWATER BENEFIT	$	1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)		
20	DSI MONETIZED POWER SALE	$	54,999
21	OTHER POWER PURCHASES (short term - omit)		
22	**Sub-Total**		
23	**Augmentation Power Purchases**		
24	AUGMENTATION POWER PURCHASES (omit - calculated below)		
25	CONSERVATION AUGMENTATION (omit)		
26	PUBLIC RESIDENTIAL EXCHANGE (net costs)	**$**	**1,107**
27	IOU RESIDENTIAL EXCHANGE after Adjustment	**$**	**251,161**
28	**Renewable Generation (expenses related to reinvestment removed)**	**$**	**41,050**
29	**Generation Conservation**		
30	LOW INCOME WEATHERIZATION & TRIBAL	$	5,812
31	ENERGY EFFICIENCY DEVELOPMENT	$	22,000
32	ENERGY WEB	$	7,000
33	**LEGACY (Until 11/1/03 this was included with line 72)**	$	2,114
34	MARKET TRANSFORMATION	$	10,000
35	TECHNOLOGY LEADERSHIP	$	1,600
36	INFRASTRUCTURE SUPPORT AND EVALUATION	$	-
37	BI-LATERAL CONTRACT ACTIVITY	$	-
38	**Sub-Total**		
39	CONSERVATION RATE CREDIT	$	32,000
40	**Power System Generation Sub-Total**		
41			
42	**PBL Transmission Acquisition and Ancillary Services**		
43	**PBL Transmission Acquisition and Ancillary Services**		
44	PBL - TRANSMISSION & ANCILLARY SERVICES		
45	Canadian Entitlement Agreement Transmission Expenses	$	27,000
46	PNCA & NTS Transmission and System Obligaton Expenses	$	1,000
47	3RD PARTY GTA WHEELING	$	50,370
48	PBL - 3RD PARTY TRANS & ANCILLARY SVCS		
49	RESERVE & OTHER SERVICES	$	6,800
50	TELEMETERING/EQUIP REPLACEMT	$	50
51	**PBL Trans Acquisition and Ancillary Services Sub-Total**		
52			
53	**Power Non-Generation Operations**		
54	**PBL System Operations**		
55	EFFICIENCIES PROGRAM (omit TMS expenses)	$	5,423
56	INFORMATION TECHNOLOGY	$	-
57	GENERATION PROJECT COORDINATION	$	7,648
58	SLICE IMPLEMENTATION (omit - calculated separately)		
59	**Sub-Total**		
60	**PBL Scheduling**		
61	OPERATIONS SCHEDULING	$	9,571
62	OPERATIONS PLANNING	$	5,969
63	**Sub-Total**		
64	**PBL Marketing and Business Support**		
65	SALES & SUPPORT	$	18,988
66	Contractual exclusion	$	(5,360)
67	Implementation Expense Exclusions - Add back		
68	PUBLIC COMMUNICATION & TRIBAL LIAISON		
69	STRATEGY, FINANCE & RISK MGMT	$	14,820
70	EXECUTIVE AND ADMINISTRATIVE SERVICES	$	3,123
71	CONSERVATION SUPPORT (EE staff costs)	$	7,996
72	**Sub-Total**		
73	**Power Non-Generation Operations Sub-Total**		

Table 2.13

Slice Costing Table

74			
75	**Fish and Wildlife/USF&W/Planning Council**		
76	**BPA Fish and Wildlife (includes F&W Shared Services)**		
77	FISH & WILDLIFE	$	199,998
78	F&W HIGH PRIORITY ACTION PROJECTS		
79	**Sub-Total**		
80	**PBL-USF&W Lower Snake Hatcheries**		
81	USF&W LOWER SNAKE HATCHERIES	$	19,690
82	**PBL - Planning Council**		
83	PLANNING COUNCIL	$	9,450
84	**PBL - ENVIRONMENTAL REQUIREMENTS**		
85	ENVIRONMENTAL REQUIREMENTS	$	300
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		
87			
88	**BPA Internal Support**		
89	**CSRS/FERS**		
90	ADDITIONAL POST-RETIREMENT CONTRIBUTION	$	15,277
91	**Corporate Support - G&A (excludes direct project support)**		
92	CORPORATE G&A	$	44,994
93	**TBL Supply Chain - Shared Services**	$	-
94	**General and Administrative/Shared Services Sub-Total**		
95			
96	**Bad Debt Expense**		
97	**Other Income, Expenses, Adjustments**	$	-
98	**Non-Federal Debt Service**		
99	**Energy Northwest Debt Service**		
##	COLUMBIA GENERATING STATION DEBT SVC	$	224,801
##	WNP-1 DEBT SVC	$	169,509
##	WNP-3 DEBT SVC	$	150,983
##	EN RETIRED DEBT		
##	EN LIBOR INTEREST RATE SWAP		
##	**Sub-Total**		
##	**Non-Energy Northwest Debt Service**		
##	TROJAN DEBT SVC	$	-
##	CONSERVATION DEBT SVC	$	5,188
##	COWLITZ FALLS DEBT SVC	$	11,571
##	WASCO DEBT SVC	$	2,168
##	**Sub-Total**		
##	**Non-Federal Debt Service Sub-Total**		
##	Depreciation (excl. TMS)	$	118,832
##	Amortization (excludes ConAug amortization)	$	56,412
##	**Total Operating Expenses**		
##			
##	**Other Expenses**		
##	Net Interest Expense	$	160,845
##	LDD	$	25,219
##	Irrigation Rate Mitigation Costs	$	12,000
##	**Sub-Total**		
##	**Total Expenses**	**$**	**2,421,823**
##			
##	**Revenue Credits**		
##	Ancillary and Reserve Service Revs. Total	$	79,306
##	Downstream Benefits and Pumping Power	$	8,921
##	4(h)(10)(c)	$	88,480
##	Colville and Spokane Settlements	$	4,600
##	FCCF		
##	Energy Efficiency Revenues	$	22,000
##	Miscellaneous	$	3,420
##	**Total Revenue Credits**	**$**	**206,727**
##			
##	**Augmentation Costs**		
##	**IOU Reduction of Risk Discount (includes interest)**	$	-
##	**Costs in this box are not subject to True-Up**		
##	**Forecasted Gross Augmentation Costs**		
##	Residual augmentation cost		
##	Other augmentation cost	$	161,123
##	Minus revenues	$	73,573
##	**Net Cost of Augmentation**	**$**	**87,550**
##			
##			
##	**Minimum Required Net Revenue calculation**		
##	Principal Payment of Fed Debt for Power	$	103,065
##	Irrigation assistance	$	7,279
##	Depreciation	$	118,832
##	Amortization	$	69,748
##	Capitalization Adjustment	$	(45,937)
##	Bond Premium Amortization	$	185
##	Principal Payment of Fed Debt exceeds non cash expenses	$	(32,484)
##	Minimum Required Net Revenues	$	-
##			
##	Annual Slice Revenue Requirement (Amounts for each FY)	**$**	**2,302,646**
##			
##			
##	**SLICE RATE CALCULATION ($)**		
##	**2009 Monthly Slice Revenue Requirement (1-Year total divided by 12 months)**		**$191,887,185**
##	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100)**		**$1,918,872**
##			
##	**ANNUAL BASE SLICE REVENUES**	**$**	**521,038,182**
##	**Annual Slice Implementation Expenses**	**$**	**2,486,000**
##	**TOTAL ANNUAL SLICE REVENUES**	**$**	**523,524,182**

Description of Ratemaking Tables

Table 2.14.1 (RDS_60A)
Allocated Costs and Unit Costs, Priority Firm Power, FY2009.
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, FY2009.
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, FY2009.
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, FY2009.
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, FY2009.
Table provides a summary of the percentages of each resource pool, FBS, Residential Exchange, and New Resources, used in ratemaking to serve each of the rate pools, PF, IP, NR, FPS.

Table 2.14.1

RDS 60A

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

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro	550,212	5.580	16.18%
Fish & Wildlife	236,501	2.399	6.96%
Trojan	2,500	0.025	0.07%
WNP #1	169,746	1.722	4.99%
WNP #2	518,334	5.257	15.25%
WNP #3	150,817	1.530	4.44%
System Augmentation	161,123	1.634	4.74%
Balancing Power Purchases	74,835	0.759	2.20%
Total Federal Base System	1,864,068	18.905	54.83%
New Resources			
Gross Residential Exchange	1,585,549	16.080	46.64%
Conservation	144,499	1.465	4.25%
BPA Programs	330,023	3.347	9.71%
TOTAL COSA ALLOCATIONS	3,924,138	39.798	110.51%
WNP #3 Excess Revenue Credit			
Nonfirm Excess Revenue Credit	(568,946)	-5.770	-16.73%
Low Density Discount Expense	24,860	0.252	0.73%
Other Revenue Credits	(193,087)	-1.958	-5.68%
Irrigation Rate Mitigation Expense	12,036	0.122	0.35%
SP Revenue Surplus/Dfct Adj.	200,874	2.037	5.91%
7(c)(2) Delta Adjustment	0	0.000	0.00%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJUSTMENTS	(524,263)	-5.317	-15.42%
Total Generation	3,399,875	**34.48**	100.00%
Billing Determinants With LDD Discount	98,601		

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 ALLOCATED COSTS	B UNIT COSTS	C PERCENT CONTRIBUTION
Rate Design Step PF Rate		($ Thousands)	(Mills/KwH)	(Percent)
PRIORITY FIRM PREFERENCE				
Revenue Reqmt @ PF Combined Rate		2,176,569	34.481	131.20%
7(b)(2) Credit		(517,612)	-8.200	-31.20%
	Subtotal	1,658,957	26.281	100.00%
Floor Rate Adjustment				
	TOTAL	1,658,957	26.281	100.00%
Billing Determinants:				
Total PF Preference Forecasted Sales		63,123	26.281	100.00%
Adjusted for LDD		63,123		
Slice Separation Step				
Revenue Reqmt @ Rate Design Step PF Pref.		1,658,957		
Slice PF Product Revenues		(521,038)		
Slice Secondary Revenue Credit Adjustment		175,193		
Non-Slice PF, Reduction in Net REP Benefit Costs				
Revenue Reqmt @ Non-Slice PF Pref.		1,313,112		
Non-Slice PF Preference Forecasted Sales		48,814	**26.900**	
PRIORITY FIRM EXCHANGE				
Revenue Reqmt @ PF Combined Rate		1,223,306	34.481	72.52%
7(b)(2) Adjustment		312,318	8.803	18.52%
7(b)(2) Industrial Adjustment		0	0.000	0.00%
7(b)(2) Exchange Cost Adjustment				
	Subtotal	1,535,625	43.284	91.04%
Floor Rate Adjustment				
	Total Energy	1,535,625	43.284	91.04%
Total Transmission		151,134	4.260	8.96%
	TOTAL	1,686,759	**47.544**	100.00%
Billing Determinants:				
Forecasted Exchange Loads		35,477	47.544	100.00%

Table 2.14.3

RATE DESIGN STUDY
Allocated Costs and Unit Costs
Industrial Firm Power Rate (IP)
($ Thousands/Unit Costs in Mills/KwH, or as Indicated)
Test Period October 2008 - September 2009

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro			
Fish & Wildlife			
Trojan			
WNP #1			
WNP #2			
WNP #3			
System Augmentation			
Balancing Power Purchases			
Total Federal Base System			
New Resources	0.01318	15.044	43.21%
Gross Residential Exchange	0.03486	39.790	114.28%
Conservation	0.00128	1.465	4.21%
Energy Services Business			
BPA Programs	0.00293	3.347	9.61%
TOTAL COSA ALLOCATIONS	0.05225	59.647	171.30%
Nonfirm Excess Revenue Credit			
Other Revenue Credits			
SP Revenue Surplus/Dfct Adj.			
7(c)(2) Delta Adjustment	(0.02293)	-26.172	-75.16%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJSTMTS	(0.02293)	-26.172	-75.16%
Total Generation	0.02932	33.475	96.14%
Total Allocated & Adjusted Costs	0.02932	33.475	96.14%
7(b)(2) Adjustments			
7(b)(2) Amount	0.00771	8.803	25.28%
7(b)(2) Industrial Adj.	(0.00682)	-7.782	-22.35%
	0.03022	34.497	99.07%
Slice Separation Step Adjustment			
7(c)(2) Slice Separation Amount	0.00028	0.322	0.93%
Total With 7(b)(2) Adjustments	0.03050	**34.819**	100.00%
Billing Determinants:			
Energy (GwH)	0.001		

Table 2.14.4

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

GENERATION ENERGY	A ALLOCATED COSTS ($ Thousands)	B UNIT COSTS (Mills/KwH)	C PERCENT CONTRIBUTION (Percent)
Federal Base System			
Hydro			
Fish & Wildlife			
Trojan			
WNP #1			
WNP #2			
WNP #3			
System Augmentation			
Balancing Power Purchases			
Total Federal Base System			
New Resources	0.013	15.044	21.98%
Gross Residential Exchange	0.035	39.790	58.13%
Conservation	0.001	1.465	2.14%
BPA Programs	0.003	3.347	4.89%
TOTAL COSA ALLOCATIONS	0.052	59.647	87.14%
Nonfirm Excess Revenue Credit			
SP Revenue Surplus/Dfct Adj.			
7(c)(2) Delta Adjustment	0.000	0.000	0.00%
7(c)(2) Floor Rate Adjustment			
TOTAL RATE DESIGN ADJSTMTS	0.000	0.000	0.00%
Total Generation Energy	0.052	59.647	87.14%
Total Allocated & Adjusted Costs	0.052	59.647	87.14%
7(b)(2) Adjustments			
7(b)(2) Amount	0.008	8.803	12.86%
7(b)(2) Industrial Adj.			
7(b(2)Exchange Cost Adjustment			
Total With 7(b)(2) Adjustments	0.060	**68.450**	100.00%
Billing Determinant / Energy (GWh)	0.001		

Table 2.14.5

RDS63

RATE DESIGN STUDY
Rate Design Step Resource Cost Contribution
($ Thousands)
Test Period October 2008 - September 2009

	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	1,193,359	1,015,054		2,208,413	54.04%	45.96%		100.00%
Priority Firm - Exchange	670,709	570,495		1,241,204	54.04%	45.96%		100.00%
Priority Firm Power - Total	1,864,068	1,585,549		3,449,616	54.04%	45.96%		100.00%
Industrial Firm Power		0	0	0		72.56%	27.44%	100.00%
New Resources Firm		0	0	0		72.56%	27.44%	100.00%
Firm Power Products and Services		216,904	82,008	298,912		72.56%	27.44%	100.00%
TOTALS	1,864,068	1,802,452	82,008	3,748,528	49.73%	48.08%	2.19%	100.00%

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CHAPTER 3: REVENUE FORECAST

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TABLE 3.5
4h10c Credits For FY 2009 ($Million)

Water Year	Purch Cost	BPA Exp.	BPA Cap.	Total	Credit @22.3%
1929	373.8	201.8	50.0	625.6	139.5
1930	212.0	201.8	50.0	463.8	103.4
1931	267.9	201.8	50.0	519.7	115.9
1932	437.3	201.8	50.0	689.1	153.7
1933	118.3	201.8	50.0	370.1	82.5
1934	-22.1	201.8	50.0	229.7	51.2
1935	281.4	201.8	50.0	533.2	118.9
1936	238.2	201.8	50.0	490.0	109.3
1937	197.3	201.8	50.0	449.1	100.2
1938	107.4	201.8	50.0	359.2	80.1
1939	311.1	201.8	50.0	562.9	125.5
1940	71.2	201.8	50.0	323.0	72.0
1941	121.4	201.8	50.0	373.2	83.2
1942	162.2	201.8	50.0	414.0	92.3
1943	179.6	201.8	50.0	431.4	96.2
1944	184.8	201.8	50.0	436.6	97.4
1945	461.3	201.8	50.0	713.1	159.0
1946	120.9	201.8	50.0	372.7	83.1
1947	99.7	201.8	50.0	351.5	78.4
1948	4.9	201.8	50.0	256.7	57.2
1949	163.7	201.8	50.0	415.5	92.7
1950	161.3	201.8	50.0	413.1	92.1
1951	26.3	201.8	50.0	278.1	62.0
1952	51.7	201.8	50.0	303.5	67.7
1953	176.1	201.8	50.0	427.9	95.4
1954	54.0	201.8	50.0	305.8	68.2
1955	100.4	201.8	50.0	352.2	78.5
1956	25.7	201.8	50.0	277.5	61.9
1957	203.3	201.8	50.0	455.1	101.5
1958	161.2	201.8	50.0	413.0	92.1
1959	45.8	201.8	50.0	297.6	66.4
1960	24.2	201.8	50.0	276.0	61.6
1961	140.5	201.8	50.0	392.3	87.5
1962	194.4	201.8	50.0	446.2	99.5
1963	113.2	201.8	50.0	365.0	81.4
1964	205.0	201.8	50.0	456.8	101.9
1965	40.8	201.8	50.0	292.6	65.3
1966	243.4	201.8	50.0	495.2	110.4
1967	127.7	201.8	50.0	379.5	84.6
1968	75.2	201.8	50.0	327.0	72.9
1969	34.2	201.8	50.0	286.0	63.8
1970	109.5	201.8	50.0	361.3	80.6
1971	130.6	201.8	50.0	382.4	85.3
1972	76.4	201.8	50.0	328.2	73.2
1973	133.5	201.8	50.0	385.3	85.9
1974	79.1	201.8	50.0	330.9	73.8
1975	153.9	201.8	50.0	405.7	90.5
1976	0.0	201.8	50.0	251.8	56.2
1977	113.4	201.8	50.0	365.2	81.4
1978	155.5	201.8	50.0	407.3	90.8
Average	**145.0**	**201.8**	**50.0**	396.8	88.5

	A	D	E	F	G
1		**Summary of Sales and Revenues**			
2		FY2008		FY2009	
3	LB5 = 0; FB = 0; SN = 0;	($000)	aMW	($000)	aMW
4	**WEST HUB**				
5	PF Requirements Service	$538,830	2,250	$559,667	2,288
6	PF Partial Service				
7	PF BLock Sales	$355,234	1,494	$334,589	1,425
8	Lookback Adjustment	$0	0	$0	0
9	PF SLICE	$412,406	1,631	$412,226	1,754
10	TOTAL WEST PF	$1,306,470	5,376	$1,306,483	5,468
11	Irrig. Mit./TAC	$4,498	45	$4,289	47
12	Pre-Subscription	$5,210	21	$4,994	21
13	**TOTAL WEST**	**$1,316,179**	**5,443**	**$1,315,767**	**5,535**
14	**Residential Exchange**	**$0**	**0**	**$0**	**0**
15	**EAST HUB**				
16	PF Requirements Service	$289,479	1,227	$309,160	1,313
17	PF Partial Service				
18	PF BLock Sales	$80,107	347	$80,123	348
19	Lookback Adjustment	$0	0	$0	0
20	PF SLICE	$92,796	359	$92,786	390
21	TOTAL EAST PF	$462,383	1,934	$482,069	2,052
22	Irrig. Mit./TAC	$16,326	150	$15,245	151
23	Pre-Subscription	$43,973	212	$35,814	181
24	**TOTAL EAST**	**$522,682**	**2,296**	**$533,128**	**2,384**
25	**BULK HUB**				
26					
27	IP LBCRAC True-ups	$0	0	$0	0
28	NW/SW Long-Term contracts	$89,079	130	$83,271	71
29	Residential Exchange Sales				
30	RL LBCRAC True-ups				
31	Committed Trading Floor Sales	$691,913	1,663	$0	0
32	Balancing Trading Floor Sales	$12,069	20	$599,046	1,578
33	Other Surplus Sales	$0	0	$0	0
34	FPS Bookouts	($103,128)	-268	$0	0
35	Canadian Entitlement Return	$0	480	$0	482
36	TOTAL BULK w/o BK Outs	**$793,061**	**2,293**	**$682,316**	**2,131**
37	Total BULK W/BK Outs	**$689,934**	**2,025**	**$682,316**	**2,131**
38	**OTHER REVENUE**				
39	Total Ancillary Services	$63,939	0	$79,306	0
40	Reserve Services	$4,493		$3,630	
41	4(h)(10)(c) credit	$96,186	0	$88,480	0
42	Network Wind Integration&Shaping	$1,490	0	$1,933	0
43	Colville & Spokane Settlements	$4,600	0	$4,600	0
44	Downstream Benefits and storage	$10,207	159	$8,921	159
45	Slice True-Up	$6,427	0	$12,955	0
46	Green Tags/Green Premiums	$3,346	0	$2,865	0
47	EE & Misc Revenues.	$17,585	0	$25,420	0
48	Aluminum Hedging	$0	0	$0	0
49	Total Miscellaneous	**$208,273**	**159**	**$228,109**	**159**
50					
51	**TOTAL REVENUE**	**$2,840,195**	**10,191**	**$2,759,320**	**10,209**
52	**check against monthly totals**	**$2,840,195**	**10,191**	**$2,759,320**	**10,209**
53	**TOTAL REVENUE w/ BK Outs**	**$2,737,067**	**9,923**	**$2,759,320**	**10,209**
54	Deferred Augmentation Expenses	**$23,024**	**0**	**$0**	**0**
55	Residual Augmentation Purchases	$0	0		0
56	Total Augmentation Costs	$29,717	27	$161,165	313
57	Other Augmentation Purchases	$6,693	27	$161,165	313
58	Committed T.F. Purchases	$408,010	725	$0	0
59	Other committed Purchases	$6,303	18	$5,375	19
60	Net Residential Exchange Expense			$319,522	0
61	Renewables	$30,850	75	$29,950	67
62	Balancing Power Purchases	$23,984	39	$69,459	137
63	Purchased Power Bookouts	($103,128)	-268	$0	0
64	Total Other Purchases	$366,019	608	$104,784	223
65	Other Purchases without Renewables	$335,169	533	$74,835	156
66	Other Purchases w/o Renewables & BKOuts	$232,041	265	$74,835	156

TABLE 3.6.1 REVENUE AT CURRENT RATES

	A	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1		Sep 15, 2008 @ 8:28															
2									Revenue ($ Thousands)								
3									Fiscal Year 2008								
4																	
5																	
6															Fiscal Year 2008		
7		WESTERN HUB	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total	aMW	GWh
8																	
9		**West Hub PF Billing Determinants**															
10		**PF Full Service**															
11		LLH Energy Flat	283,120	345,655	421,718	416,119	335,807	360,236	310,238	271,506	257,731	247,315	249,567	246,049	3,745,060	426	3745
12		HLH Energy Flat	482,025	513,331	572,202	630,594	537,035	537,351	498,287	418,204	395,084	389,591	412,680	389,453	5,775,838	658	5776
13		PF Flat LLH Energy Rate	$21.76	$23.10	$24.26	$20.30	$20.50	$19.49	$17.93	$14.41	$10.02	$17.01	$20.18	$22.54			
14		PF Flat HLH Energy Rate	$29.70	$31.68	$33.06	$28.07	$28.66	$26.59	$24.95	$20.84	$18.87	$23.24	$27.21	$28.09			
15		LLH Energy Revenue Flat Revenue = 11*13/1000	$6,161	$7,985	$10,231	$8,447	$6,884	$7,021	$5,563	$3,912	$2,582	$4,207	$5,036	$5,546	$73,575		
16		HLH Energy Revenue Flat Revenue= 12*14/1000	$14,316	$16,262	$18,917	$17,701	$15,391	$14,288	$12,432	$8,715	$7,455	$9,054	$11,229	$10,940	$156,701		
17		Demand	1,487	1,561	1,643	1,708	1,655	1,692	1,679	1,094	1,008	1,028	1,018	1,006	16,579		
18		PF GSP Demand Rate	$1.94	$2.07	$2.18	$1.85	$1.88	$1.75	$1.64	$1.36	$1.25	$1.53	$1.79	$1.85			
19		Demand Revenue = 23*24	$2,885	$3,247	$3,582	$3,161	$3,111	$2,961	$2,753	$1,488	$1,260	$1,573	$1,822	$1,861	$29,704		
20		Load Variance	777,780	871,557	1,008,575	1,060,992	885,546	910,585	820,427	702,977	668,026	680,802	706,847	676,532	9,770,644	1112	9771
21		PF Ld Variance Rate	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47			
22		Load Variance Revenue = 26*27/1000	$366	$410	$474	$499	$416	$428	$386	$330	$314	$320	$332	$318	$4,592		
23		Low Density Discount Percent =30/(15+16+21+22+25+28)	-1.85%	-1.85%	-1.91%	-1.91%	-1.87%	-1.88%	-1.84%	-1.80%	-1.80%	-2.08%	-2.13%	-2.08%			
24		Low Density Discount	-$439	-$515	-$633	-$569	-$483	-$465	-$389	-$260	-$209	-$316	-$392	-$388	-$5,060		
25	0.2569	LBCRAC True-up/Lookback Adjust												$0	$0		
26		PF Other Energy	0	0	0	0	0	0	0	0	0						
27		PF Other revenues	$5	$0	$13	$0	$0	$0	$0	$0	$0				$18		
28																	
29		**PF Partial Service**															
30		LLH Energy Flat	248,002	283,572	429,768	452,704	356,929	394,442	345,972	401,435	325,715	320,972	309,053	299,160	4,167,725	474	4,168
31		HLH Energy Flat	360,999	361,393	534,000	638,811	534,964	554,925	527,982	556,732	447,889	513,438	531,580	516,669	6,079,382	692	6,079
32		LLH Energy Revenue Flat (40*13)/1000	$5,397	$6,551	$10,426	$9,190	$7,317	$7,688	$6,203	$5,786	$3,369	$5,460	$6,237	$6,743	$80,366		
33		HLH Energy Revenue Flat (41*14)/1000	$10,722	$11,449	$17,654	$17,931	$15,332	$14,755	$13,173	$11,605	$8,457	$11,932	$14,464	$14,513	$161,989		
34		GSP Demand	1,003	1,082	1,717	1,871	1,609	1,694	1,754	1,439	1,317	1,385	1,354	1,394	17,620		
35		Demand Revenue (44*24)	$1,947	$2,250	$3,744	$3,461	$3,024	$2,965	$2,876	$1,957	$1,645	$2,119	$2,424	$2,579	$30,991		
36		Load Variance	679,507	714,959	1,175,055	1,332,608	1,115,800	1,174,016	1,097,036	1,027,051	988,540	1,042,227	1,037,856	1,010,964	12,395,617	1411	12396
37		Load Variance Revenue (45*27)/1000	$319	$336	$552	$626	$524	$552	$516	$483	$465	$490	$488	$475	$5,826		
38	0.0166	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39		PF Other Energy	0	0	0	0	0	0	1	0	0						
40		PF Other revenues	$0	$117	$0	$0	$0	$10	$0	$0	$0				$127		
41																	
42		**PF Block Service**															
43		LLH Energy Flat	469,248	617,925	629,560	588,104	527,768	540,858	381,824	324,668	292,232	332,526	370,920	432,960	5,508,593	627	5,509
44		HLH Energy Flat	732,672	874,400	829,056	790,816	745,200	732,160	547,872	439,641	386,456	460,013	500,323	578,800	7,617,409	867	7,617
45		LLH Energy Revenue Flat (55*13)/1000	$10,211	$14,274	$15,273	$11,939	$10,819	$10,541	$6,846	$4,678	$2,928	$5,656	$7,485	$9,759	$110,410		
46		LLH Energy Revenue Stepped (56*19)/1000													$0		
47		HLH Energy Revenue Flat (56*14)/1000	$21,760	$27,701	$27,409	$22,198	$21,357	$19,468	$13,669	$9,162	$7,292	$10,691	$13,614	$16,258	$210,581		
48		HLH Energy Revenue Stepped (57*20)/1000													$0		
49		GSP Demand	1,987	2,523	2,029	2,056	1,996	1,888	1,411	1,272	1,158	1,289	1,369	1,499	20,477		
50		Demand Revenue (62*24)	$3,855	$5,248	$4,423	$3,804	$3,752	$3,304	$2,314	$1,730	$1,448	$1,972	$2,451	$2,773	$37,073		
51	0.4824	LBCRAC True-up/Lookback Adjust												$0	$0		
52		PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53		Low Density Discount Percent = 70/(59+60+61+62+64)	-0.72%	-0.63%	-0.78%	-0.84%	-0.81%	-0.75%	-1.03%	-0.91%	-0.85%	-0.76%	-0.68%	-0.95%			
54		Low-Density Discount	-$258	-$297	-$366	-$318	-$293	-$250	-$235	-$142	-$99	-$138	-$161	-$274	-$2,830		
55		PF Other Energy													0		
56		PF Block Other Revenues													$0		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	A	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1		Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)									
3								Fiscal Year 2008									
4																	
5																	
6															Fiscal Year 2008		
7		WESTERN HUB	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Total	aMW	GWh
57										$1,188	$1,332	$2,542	$2,606		$7,668		
58		**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	42,503	59,544	44,976	39,178	0	186,201	21	186
59		**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	27,604	38,968	76,479	66,709	0	209,760	24	210
60		**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$691	$700	$1,460	$1,648	$0	$4,498		
61															$0		
62																	
63		**TAC LLH**													0	-	-
64		**TAC HLH**													0	-	-
65		**TAC Demand**													0		
66		**TAC Revenues**													$0		
67																	
68		PF SLICE															
69		Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1631	
70		Slice rate	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877			
71		Slice Charges ($000) 90*91	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,744	$34,744	$416,903		
72		Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	0.818	LBCRAC True-up/Lookback Adjust												$0	$0		
74		LDD Percentage	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75		Low-Density Discount	-390	-390	-390	-390	-390	-390	-390	-390	-390	-$389	-$389	-$389	-$4,677		
76		Slice Other	$0	$69		$4	$25	$15	$5	$23	$40				$180		
77		West Hub FPS (Pre-Subscription) Sales															
78		LLH Energy Full Service	6,134	7,063	7,561	7,219	6,277	7,460	5,629	6,079	5,715	6,888	6,888	6,720	79,632	9	80
79		LLH Energy Revenue	$134	$162	$181	$149	$131	$149	$106	$97	$72	$131	$149	$158	$1,619		
80		HLH Energy Full Service	8,163	8,682	8,488	8,900	8,460	9,379	10,361	10,678	9,845	8,736	8,736	8,400	108,828	12	109
81		HLH Energy Revenue	$229	$260	$263	$199	$232	$242	$309	$295	$264	$206	$234	$231	$2,965		
82		GSP Demand	21	21	19	24	22	23	18	20	20	17	17	17	240		
83		Demand Revenue	$29	$31	$30	$33	$30	$29	$20	$18	$16	$52	$61	$63	$412		
84		Load Variance	14,864	17,222	17,533	17,638	16,035	17,977	16,379	17,181	15,574	15,624	15,624	15,120	196,772	22	197
85		Load Variance Revenue	$7	$8	$8	$8	$8	$8	$8	$8	$7	$7	$7	$7	$92		
86		Low-Density Discount													$0		
87		LT SURPLUS FB CRAC															
88		Netrwork Wind Integration Service													$0		
89		Other Pre-Subscription revenues	$12	$13	$15	$16	$13	$13	$12	$14	$14				$122		
90																	
91		Public Agency Residential Exchange															
92		Monthly Energy Flat													0	-	-
93		Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94		Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95		GSP Demand													0		
96		GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97		Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98		**Total**	$112,007	$129,842	$146,548	$132,825	$121,918	$118,060	$100,915	$84,921	$72,333	$89,229	$101,482	$105,918	$1,315,999		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	A	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1		Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)									
3								Fiscal Year 2009									
4																	
5																	
6															Fiscal Year 2009		
7		WESTERN HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8															$0		
9		**West Hub PF Billing Determinants**													$0		
10		**PF Full Service**													$0		
11		LLH Energy Flat	267,493	340,904	377,097	380,354	324,016	327,388	280,575	270,874	228,210	244,606	246,832	243,399	3,531,748	403	3532
12		HLH Energy Flat	457,485	499,338	582,847	588,706	515,161	520,647	458,477	400,967	385,931	387,548	410,854	387,604	5,595,565	639	5596
13		PF Flat LLH Energy Rate	$21.76	$23.10	$24.26	$20.30	$20.50	$19.49	$17.93	$14.41	$10.02	$17.01	$20.18	$22.54			
14		PF Flat HLH Energy Rate	$29.70	$31.68	$33.06	$28.07	$28.66	$26.59	$24.95	$20.84	$18.87	$23.24	$27.21	$28.09			
15		LLH Energy Revenue Flat Revenue = 11*13/1000	$5,821	$7,875	$9,148	$7,721	$6,642	$6,381	$5,031	$3,903	$2,287	$4,161	$4,981	$5,486	$69,437		
16		HLH Energy Revenue Flat Revenue= 12*14/1000	$13,587	$15,819	$19,269	$16,525	$14,765	$13,844	$11,439	$8,356	$7,283	$9,007	$11,179	$10,888	$151,960		
17		Demand	1,486	1,644	1,662	1,828	1,758	1,555	1,341	1,055	993	1,045	1,034	1,022	16,423		
18		PF GSP Demand Rate	$1.94	$2.07	$2.18	$1.85	$1.88	$1.75	$1.64	$1.36	$1.25	$1.53	$1.79	$1.85			
19		Demand Revenue = 23*24	$2,883	$3,403	$3,623	$3,382	$3,305	$2,721	$2,199	$1,435	$1,241	$1,599	$1,851	$1,891	$29,533		
20		Load Variance	783,522	897,610	1,019,706	1,028,525	892,992	907,000	795,492	731,181	672,338	691,674	717,910	687,154	9,825,104	1122	9825
21		PF Ld Variance Rate	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47			
22		Load Variance Revenue = 26*27/1000	$368	$422	$479	$483	$420	$426	$374	$344	$316	$325	$337	$323	$4,618		
23		Low Density Discount Percent =30/(15+16+21+22+25+28)	-2.15%	-2.17%	-2.18%	-2.18%	-2.21%	-2.17%	-2.14%	-2.13%	-2.10%	-2.13%	-2.17%	-2.12%			
24		Low Density Discount	-$488	-$598	-$709	-$613	-$556	-$508	-$408	-$299	-$234	-$321	-$399	-$394	-$5,527		
25	0.2569	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
26		PF Other Energy															
27		PF Other revenues													$0		
28															$0		
29		**PF Partial Service**													$0		
30		LLH Energy Flat	285,591	326,535	329,856	361,329	336,006	325,845	311,882	312,789	281,604	331,805	315,969	305,767	3,824,978	437	3,825
31		HLH Energy Flat	568,526	622,810	720,145	704,900	619,001	641,802	575,586	537,035	508,643	521,800	543,923	528,725	7,092,896	810	7,093
32		LLH Energy Revenue Flat (40*13)/1000	$6,214	$7,543	$8,002	$7,335	$6,888	$6,351	$5,592	$4,507	$2,822	$5,644	$6,376	$6,892	$74,167		
33		HLH Energy Revenue Flat (41*14)/1000	$16,885	$19,731	$23,808	$19,787	$17,741	$17,066	$14,361	$11,192	$9,598	$12,127	$14,800	$14,852	$191,946		
34		GSP Demand	1,794	1,934	2,064	2,126	2,119	1,913	1,722	1,545	1,362	1,415	1,384	1,425	20,803		
35		Demand Revenue (44*24)	$3,480	$4,003	$4,500	$3,933	$3,984	$3,348	$2,824	$2,101	$1,703	$2,165	$2,477	$2,636	$37,154		
36		Load Variance	1,060,229	1,179,368	1,292,589	1,311,890	1,191,130	1,187,964	1,115,869	1,070,225	1,017,310	1,061,368	1,056,649	1,029,577	13,574,168	1550	13574
37		Load Variance Revenue (45*27)/1000	$498	$554	$608	$617	$560	$558	$524	$503	$478	$499	$497	$484	$6,380		
38	0.0166	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39		PF Other Energy															
40		PF Other revenues													$0		
41															$0		
42		**PF Block Service**													$0		
43		LLH Energy Flat	396,271	528,753	581,216	590,400	515,261	545,763	384,226	334,643	278,890	332,526	370,920	432,960	5,291,829	604	5,292
44		HLH Energy Flat	567,259	655,488	790,400	793,728	720,038	738,400	551,158	436,320	402,022	460,013	500,323	578,800	7,193,949	821	7,194
45		LLH Energy Revenue Flat (55*13)/1000	$8,623	$12,214	$14,100	$11,985	$10,563	$10,637	$6,889	$4,822	$2,794	$5,656	$7,485	$9,759	$105,528		
46		LLH Energy Revenue Stepped (56*19)/1000													$0		
47		HLH Energy Revenue Flat (56*14)/1000	$16,848	$20,766	$26,131	$22,280	$20,636	$19,634	$13,751	$9,093	$7,586	$10,691	$13,614	$16,258	$197,288		
48		HLH Energy Revenue Stepped (57*20)/1000													$0		
49		GSP Demand	1,419	1,833	2,015	2,066	2,006	1,906	1,419	1,296	1,149	1,289	1,369	1,499	19,266		
50		Demand Revenue (62*24)	$2,753	$3,794	$4,393	$3,822	$3,771	$3,336	$2,327	$1,763	$1,436	$1,972	$2,451	$2,773	$34,591		
51	0.4824	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52		PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53		Low Density Discount Percent = 70/(59+60+61+62+64)	-0.92%	-0.80%	-0.82%	-0.84%	-0.82%	-0.74%	-1.02%	-0.90%	-0.83%	-0.74%	-0.67%	-0.95%			
54		Low-Density Discount	-$259	-$295	-$368	-$318	-$285	-$250	-$234	-$141	-$98	-$136	-$159	-$274	-$2,817		
55		PF Other Energy													0		
56		PF Block Other Revenues													$0		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	A	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1		Sep 15, 2008 @ 8:28															
2									Revenue ($ Thousands)								
3									Fiscal Year 2009								
4																	
5																	
6																Fiscal Year 2009	
7		WESTERN HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
57										$1,412	$1,667	$2,542	$2,606		$8,227		
58		**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,976	39,178	0	152,052	17	152
59		**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	48,163	67,322	76,479	66,709	0	258,673	30	259
60		**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$700	$693	$1,356	$1,541	$0	$4,289		
61															$0		
62																	
63		**TAC LLH**													0	-	-
64		**TAC HLH**													0	-	-
65		**TAC Demand**													0		
66		**TAC Revenues**													$0		
67																	
68		PF SLICE															
69		Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1754	
70		Slice rate	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877			
71		Slice Charges ($000) 90*91	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$34,741	$416,897		
72		Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	0.818	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
74		LDD Percentage	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75		Low-Density Discount	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$4,671		
76		Slice Other															
77		West Hub FPS (Pre-Subscription) Sales															
78		LLH Energy Full Service	6,552	7,077	6,888	6,888	6,048	6,867	6,384	7,224	6,384	6,888	6,888	6,720	80,808	9	81
79		LLH Energy Revenue	$142	$160	$162	$141	$125	$136	$119	$115	$80	$124	$141	$149	$1,595		
80		HLH Energy Full Service	9,072	8,064	8,736	8,736	8,064	8,736	8,736	8,400	8,736	8,736	8,736	8,400	103,152	12	103
81		HLH Energy Revenue	$252	$236	$265	$232	$217	$222	$210	$176	$169	$199	$226	$223	$2,627		
82		GSP Demand	17	17	17	17	17	17	17	17	17	17	17	17	204		
83		Demand Revenue	$63	$67	$71	$60	$61	$57	$53	$44	$40	$50	$58	$60	$686		
84		Load Variance	15,624	15,141	15,624	15,624	14,112	15,603	15,120	15,624	15,120	15,624	15,624	15,120	183960	21	184
85		Load Variance Revenue	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$7	$86		
86		Low-Density Discount													$0		
87		LT SURPLUS FB CRAC															
88		Netrwork Wind Integration Service													$0		
89		Other Pre-Subscription revenues													$0		
90																	
91		Public Agency Residential Exchange															
92		Monthly Energy Flat													0	-	-
93		Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94		Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95		GSP Demand													0		
96		GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97		Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98		**Total**	$112,031	$130,055	$147,842	$131,731	$123,195	$118,317	$99,411	$82,973	$72,553	$89,476	$101,816	$106,366	$1,315,767		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)								
3								**Fiscal Year 2008**								
4																
5																
6															**Fiscal Year 2008**	
7	**Eastern HUB**	**Oct-07**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Total**	**aMW**	**GWh**
8																
9	East Hub PF Billing Determinants															
10	**PF Full Service**															
11	LLH Energy Flat	217,399	255,530	314,529	320,179	253,375	258,373	244,478	216,954	198,247	250,543	233,422	277,962	3,040,990	346	3,041
12	HLH Energy Flat	412,294	433,091	504,692	560,113	463,218	448,041	442,980	359,797	318,984	371,667	385,464	411,161	5,111,502	582	5,112
13	PF Flat LLH Energy Rate	$21.76	$23.10	$24.26	$20.30	$20.50	$19.49	$17.93	$14.41	$10.02	$17.01	$20.18	$22.54			
14	PF Flat HLH Energy Rate	$29.70	$31.68	$33.06	$28.07	$28.66	$26.59	$24.95	$20.84	$18.87	$23.24	$27.21	$28.09			
15	LLH Energy Revenue Flat= (11*13)/1000	$4,639	$5,903	$7,630	$6,500	$5,194	$5,036	$4,383	$3,126	$1,986	$4,262	$4,710	$6,265	$59,636		
16	HLH Energy Revenue Flat= (12*14)/1000	$11,968	$13,263	$15,933	$15,378	$12,948	$11,751	$11,022	$7,672	$6,236	$8,638	$10,488	$11,549	$136,847		
17	GSP Demand	1,162	1,282	1,384	1,475	1,266	1,264	1,313	983	1,381	1,424	1,327	1,155	15,415		
18	PF GSP Demand Rate	$1.94	$2.07	$2.18	$1.85	$1.88	$1.75	$1.64	$1.36	$1.25	$1.53	$1.79	$1.85			
19	Demand Revenue= (23*24)	$2,242	$2,633	$2,965	$2,723	$2,371	$2,220	$2,176	$1,369	$1,747	$2,179	$2,375	$2,137	$27,137		
20	PF Ld Variance	638,640	696,552	829,627	886,345	722,064	714,780	695,453	740,535	746,609	876,598	839,346	695,498	9,082,047	1,034	9,082
21	PF Ld Variance Rate	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47			
22	Load Variance= (26*27)/1000	$300	$327	$390	$417	$339	$336	$327	$348	$351	$349	$338	$327	$4,149		
23	Low Density Discount Percent=28/(15+16+21+22+25+28)	-3.86%	-3.72%	-3.79%	-3.77%	-3.74%	-3.78%	-4.00%	-3.74%	-3.55%	-3.41%	-3.41%	-4.00%			
24	Low Density Discount	-$740	-$824	-$1,020	-$942	-$779	-$731	-$716	-$469	-$366	-$526	-$612	-$812	-$8,537		
25	LBCRAC True-up/Lookback Adjust												$0	$0		
26	PF Other Energy	0	0	0	0	0	0	0	0	0				0	0	0
27	PF Other Revenues	$7	$0	$15	$0	$0	$0	$0	$0	$0				$22		
28																
29	**PF Partial Service**															
30	LLH Energy Flat	81,212	94,873	113,152	113,744	93,415	95,889	83,922	75,237	76,151	84,498	76,536	81,727	1,070,356	122	1,070
31	HLH Energy Flat	128,640	134,334	146,820	162,272	139,794	134,575	128,158	108,450	110,158	121,913	122,857	115,216	1,553,188	177	1,553
32	LLH Energy Revenue Flat = 39*13/1000	$1,767	$2,192	$2,745	$2,309	$1,915	$1,869	$1,505	$1,084	$763	$1,437	$1,545	$1,842	$20,973		
33	HLH Energy Revenue Flat = 40*14/1000	$3,821	$4,256	$4,854	$4,555	$4,007	$3,578	$3,198	$2,260	$2,079	$2,833	$3,343	$3,236	$42,019		
34	GSP Demand	355	414	407	466	364	361	388	298	342	328	316	300	4,338		
35	Demand Revenue = 47*24	$688	$862	$887	$861	$685	$631	$636	$405	$427	$502	$566	$556	$7,706		
36	Load Variance	216,762	235,592	267,069	280,303	240,056	238,167	218,750	195,909	200,610	223,359	214,969	204,503	2,736,047	311	2,736
37	Load Variance = 49*27/1000	$102	$111	$126	$132	$113	$112	$103	$92	$94	$104	$100	$96	$1,284		
38	LBCRAC True-up/Lookback Adjust												$0	$0		
39	Low Density Discount Percent= 56/(42+43+46+47+49+51)	-2.57%	-2.43%	-2.34%	-2.36%	-2.38%	-2.42%	-2.42%	-2.32%	-2.49%	-2.65%	-2.65%	-2.73%			
40	Low Density Discount	-$164	-$180	-$202	-$185	-$160	-$150	-$132	-$89	-$84	-$129	-$147	-$156	-$1,779		
41	PF Other Energy	0	0	0	0	0	0	0	0	0				0	0	0
42	PF Other Revenue	$0	$0	$7	$7	$0	$3	$5	$1	$0				$23		
43																
44	**PF Block Service**															
45	LLH Energy Flat	105,768	109,782	128,312	124,640	111,296	112,161	124,336	117,503	112,545	99,647	89,713	116,960	1,352,663	154	1,353
46	HLH Energy Flat	146,448	136,800	149,200	158,080	150,400	142,688	170,144	135,669	122,947	126,381	113,776	146,200	1,698,733	193	1,699
47	LLH Energy Revenue Flat=(61*13)/1000	$2,302	$2,536	$3,113	$2,530	$2,282	$2,186	$2,229	$1,693	$1,128	$1,695	$1,810	$2,636	$26,140		
48	HLH Energy Revenue Flat=(62*14)/1000	$4,350	$4,334	$4,933	$4,437	$4,310	$3,794	$4,245	$2,827	$2,320	$2,937	$3,096	$4,107	$45,690		
49	GSP Demand	339	342	373	380	376	343	409	452	494	493	420	366	4,787		
50	Demand Revenue=(69*24)	$658	$711	$813	$703	$707	$600	$671	$615	$618	$754	$751	$676	$8,277		
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount	$0	$0	$0	$0	$0	$0	$0	$0	$0				$0		
53	PF Other Energy	0	0	0	0	0	0	0	0	0				0	0	0
54	PF Block Other Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0						
55																

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Sep 15, 2008 @ 8:28															
2							Revenue ($ Thousands)									
3							**Fiscal Year 2008**									
4																
5																
6															**Fiscal Year 2008**	
7	**Eastern HUB**	**Oct-07**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Total**	**aMW**	**GWh**
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%	4.1191%	359	
58	Slice Rate	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877			
59	Slice Charges	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$92,784		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues	$1	$0		$7	$0	$1	$0	$4	$0				$12		
62																
63	**East Hub FPS (Pre-Subscription) Sales**															
64	LLH Energy Pre-Sub	48,174	63,675	84,378	83,988	68,061	67,618	55,793	54,402	54,435	60,453	56,671	48,288	745,936	85	746
65	LLH Energy Revenue	$1,072	$1,443	$1,946	$1,839	$1,494	$1,461	$1,098	$640	$551	$846	$1,053	$1,086	$14,528		
66	HLH Energy Pre-Sub	79,557	89,708	109,621	120,752	100,327	95,204	83,442	79,826	82,672	101,385	95,304	78,510	1,116,308	127	1,116
67	HLH Energy Revenue	$2,071	$2,372	$2,968	$3,088	$2,591	$2,390	$1,898	$1,187	$1,164	$1,763	$2,160	$2,000	$25,651		
68	GSP Demand	238	312	329	394	297	287	275	221	245	278	265	235	3,376		
69	Demand Revenue	$291	$393	$422	$458	$360	$328	$307	$243	$251	$317	$331	$305	$4,006		
70	Load Variance	109,693	125,780	159,585	167,049	139,113	134,735	117,117	114,997	116,873	141,838	133,391	110,507	1,570,677	179	1,571
71	Load Variance Revenue	$59	$68	$86	$90	$75	$73	$64	$62	$64	$81	$76	$63	$863		
72	Low Density Discount	-$74	-$99	-$114	-$125	-$102	-$98	-$75	-$21	-$16	-$109	-$136	-$131	-$1,100		
73	Wind Integration Service													$0		
74	Other Presubscription revenues	$2	$3	$3	$3	$3	$3	$2	$3	$3				$25		
75	**Irrigation Mitigation**								$4,032	$4,590	$8,351	$8,186		$25,159		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	151,282	216,012	154,255	123,084	0	644,632	73	645
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	88,848	128,555	246,442	209,575	0	673,420	77	673
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,652	$1,760	$2,759	$2,987	$0	$9,158		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$970	$1,048	$2,560	$2,589	$0	$7,168		
80														$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$43,093	$48,035	$56,233	$52,516	$46,082	$43,125	$40,677	$33,409	$29,855	$40,984	$45,156	$43,514	$522,682		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Sep 15, 2008 @ 8:28															
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														$0		
9	East Hub PF Billing Determinants													$0		
10	**PF Full Service**													$0		
11	LLH Energy Flat	274,674	321,173	371,644	371,718	313,807	293,897	271,917	254,439	237,017	267,379	248,557	292,134	3,518,356	402	3,518
12	HLH Energy Flat	441,601	452,884	525,640	538,653	471,457	451,489	423,292	371,306	371,072	397,064	410,744	431,866	5,287,068	604	5,287
13	PF Flat LLH Energy Rate	$21.76	$23.10	$24.26	$20.30	$20.50	$19.49	$17.93	$14.41	$10.02	$17.01	$20.18	$22.54			
14	PF Flat HLH Energy Rate	$29.70	$31.68	$33.06	$28.07	$28.66	$26.59	$24.95	$20.84	$18.87	$23.24	$27.21	$28.09			
15	LLH Energy Revenue Flat= (11*13)/1000	$5,977	$7,419	$9,016	$7,546	$6,433	$5,728	$4,875	$3,666	$2,375	$4,548	$5,016	$6,585	$69,185		
16	HLH Energy Revenue Flat= (12*14)/1000	$13,116	$14,347	$17,378	$15,120	$13,512	$12,005	$10,561	$7,738	$7,002	$9,228	$11,176	$12,131	$143,314		
17	GSP Demand	1,279	1,384	1,448	1,544	1,535	1,263	1,187	1,164	1,352	1,494	1,391	1,211	16,252		
18	PF GSP Demand Rate	$1.94	$2.07	$2.18	$1.85	$1.88	$1.75	$1.64	$1.36	$1.25	$1.53	$1.79	$1.85			
19	Demand Revenue= (23*24)	$2,481	$2,865	$3,157	$2,856	$2,886	$2,210	$1,947	$1,583	$1,690	$2,286	$2,490	$2,240	$28,691		
20	PF Ld Variance	723,305	780,555	902,499	912,635	789,103	750,608	699,338	782,637	831,697	918,830	879,761	730,376	9,701,344	1,107	9,701
21	PF Ld Variance Rate	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47	$0.47			
22	Load Variance= (26*27)/1000	$340	$367	$424	$429	$371	$353	$329	$368	$391	$432	$413	$343	$4,560		
23	Low Density Discount Percent=28/(15+16+21+22+25+28)	-3.64%	-3.43%	-3.46%	-3.43%	-3.43%	-3.47%	-3.76%	-3.50%	-3.37%	-3.31%	-3.32%	-3.90%			
24	Low Density Discount	-$797	-$858	-$1,038	-$889	-$796	-$705	-$666	-$467	-$386	-$547	-$634	-$831	-$8,613		
25	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
26	PF Other Energy													0	0	0
27	PF Other Revenues													$0		
28																
29	**PF Partial Service**															
30	LLH Energy Flat	86,319	100,465	113,319	111,227	96,404	95,276	83,266	80,672	77,177	87,761	79,489	84,727	1,096,102	125	1,096
31	HLH Energy Flat	134,056	138,983	155,805	157,359	141,795	143,390	124,573	115,627	119,115	126,533	127,481	119,377	1,604,094	183	1,604
32	LLH Energy Revenue Flat = 39*13/1000	$1,878	$2,321	$2,749	$2,258	$1,976	$1,857	$1,493	$1,162	$773	$1,493	$1,604	$1,910	$21,475		
33	HLH Energy Revenue Flat = 40*14/1000	$3,981	$4,403	$5,151	$4,417	$4,064	$3,813	$3,108	$2,410	$2,248	$2,941	$3,469	$3,353	$43,357		
34	GSP Demand	378	396	423	435	413	377	333	313	307	340	328	311	4,354		
35	Demand Revenue = 47*24	$733	$820	$922	$805	$776	$660	$546	$426	$384	$520	$587	$575	$7,754		
36	Load Variance	228,188	247,018	276,937	274,833	245,254	246,468	215,399	208,913	210,957	231,243	222,546	211,664	2,819,420	322	2,819
37	Load Variance = 49*27/1000	$107	$116	$130	$129	$115	$116	$101	$98	$99	$109	$105	$99	$1,325		
38	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39	Low Density Discount Percent= 56/(42+43+46+47+49+51)	-2.66%	-2.51%	-2.44%	-2.44%	-2.45%	-2.43%	-2.56%	-2.52%	-2.67%	-2.69%	-2.69%	-2.76%			
40	Low Density Discount	-$178	-$192	-$218	-$186	-$170	-$157	-$134	-$103	-$94	-$136	-$155	-$164	-$1,888		
41	PF Other Energy													0	0	0
42	PF Other Revenue													$0		
43																
44	**PF Block Service**															
45	LLH Energy Flat	105,768	115,557	123,066	124,935	108,490	112,063	124,549	117,613	99,135	99,647	89,713	116,960	1,337,496	153	1,337
46	HLH Energy Flat	146,448	131,674	156,083	158,454	144,653	142,563	170,435	136,760	135,657	126,381	113,776	146,200	1,709,084	195	1,709
47	LLH Energy Revenue Flat=(61*13)/1000	$2,302	$2,669	$2,986	$2,536	$2,224	$2,184	$2,233	$1,695	$993	$1,695	$1,810	$2,636	$25,964		
48	HLH Energy Revenue Flat=(62*14)/1000	$4,350	$4,171	$5,160	$4,448	$4,146	$3,791	$4,252	$2,850	$2,560	$2,937	$3,096	$4,107	$45,867		
49	GSP Demand	339	343	375	381	377	343	410	454	496	493	420	366	4,797		
50	Demand Revenue=(69*24)	$658	$710	$818	$705	$709	$600	$672	$617	$620	$754	$752	$677	$8,292		
51	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52	Low-Density Discount													$0		
53	PF Other Energy													0	0	0
54	PF Block Other Revenue															
55																

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Sep 15, 2008 @ 8:28															
2							Revenue ($ Thousands)									
3							Fiscal Year 2009									
4																
5																
6														Fiscal Year 2009		
7	Eastern HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
56	**PF SLICE**															
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%	4.1191%	390	
58	Slice Rate	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877	$1,877			
59	Slice Charges	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$7,732	$92,786		
60	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
61	Slice Other Revenues															
62																
63	**East Hub FPS (Pre-Subscription) Sales**															
64	LLH Energy Pre-Sub	46,494	54,014	63,943	62,320	57,256	55,449	43,410	44,697	45,950	53,675	50,033	41,946	619,187	71	619
65	LLH Energy Revenue	$1,028	$1,208	$1,449	$1,367	$1,258	$1,204	$860	$499	$465	$718	$907	$932	$11,894		
66	HLH Energy Pre-Sub	74,169	83,834	96,204	97,523	83,574	81,905	66,473	72,860	73,441	89,228	83,501	67,958	970,670	111	971
67	HLH Energy Revenue	$1,872	$2,145	$2,487	$2,432	$2,097	$1,979	$1,473	$1,005	$963	$1,448	$1,806	$1,677	$21,384		
68	GSP Demand	248	264	291	292	282	251	216	201	212	241	229	200	2,927		
69	Demand Revenue	$294	$320	$364	$337	$331	$287	$238	$206	$210	$255	$259	$234	$3,335		
70	Load Variance	120,982	134,400	155,201	157,002	135,608	135,482	115,226	120,510	123,318	144,075	135,522	112,318	1,589,644	181	1,590
71	Load Variance Revenue	$69	$76	$88	$89	$77	$77	$65	$69	$70	$82	$77	$64	$903		
72	Low Density Discount	-$146	-$168	-$191	-$197	-$174	-$166	-$124	-$76	-$78	-$111	-$138	-$134	-$1,702		
73	Wind Integration Service													$0		
74	Other Presubscription revenues													$0		
75	**Irrigation Mitigation**								$4,409	$5,419	$8,351	$8,186		$26,365		
76	Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652	128,555	154,255	123,084	0	498,546	57	499
77	Irrigation Mitigation HLH	0	0	0	0	0	0	0	147,477	218,891	246,442	209,575	0	822,385	94	822
78	Irrigation Mitigation Flat Revenues	$0	$0	$0	$0	$0	$0	$0	$1,202	$1,348	$2,577	$2,803	$0	$7,929		
79	Irrigation Mitigation Stepped Revenues	$0	$0	$0	$0	$0	$0	$0	$1,234	$1,258	$2,393	$2,431	$0	$7,316		
80														$0		
81	**TAC**															
82	TAC LLH													0	0	0
83	TAC HLH													0	0	0
84	TAC Demand													0		
85	TAC Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
86																
87																
88	Total	$45,797	$50,471	$58,564	$51,934	$47,567	$43,569	$39,562	$33,914	$30,623	$41,354	$45,606	$44,168	$533,128		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)								
3								**Fiscal Year 2008**								
4		744	721	744	744	696	743	720	744	720	744	744	720	**Fiscal Year 2008**		
5		432	400	400	416	400	416	416	416	400	416	416	400			
6		312	321	344	328	296	327	304	328	320	328	328	320			
7	**Bulk HUB**	**Oct-07**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Total**	**aMW**	**GWh**
8																
9	**Investor-Owned Utilities Residential Exchange**															
10	Demand (MW)															
11	Demand Rate															
12	HLH Energy (MWhr)															
13	LLH Energy (MWhr)															
14	Residential Exchange Rate															
15																
16	**Residential Exchange Revenue ($000)**															
17	LB CRAC True-up/Lookback adjustment													$0		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	IP LBCRAC True-up													$0		
21	**PAC capacity, WNP-3 and other L-T contracts**															
22	Demand (MW)	799	886	795	795	795	713	713	903	915	1,017	878	766	9,975		
23	HLH Energy (MWhr)	143,176	201,939	201,547	246,868	205,829	180,458	176,757	259,076	262,998	290,093	172,526	58,962	2,400,229	273	2,400
24	LLH Energy (MWhr)	-207,169	-151,305	-115,511	-106,686	-104,331	-81,169	-117,864	-76,682	-133,824	-11,732	-20,005	-128,632	-1,254,910	-143	-1,255
25	Energy (aMW)	-86	70	116	188	146	134	82	245	179	374	205	-97	1,556	130	1,145
26	Revenue ($ Thousand)	$3,964	$9,781	$9,959	$9,971	$9,465	$7,343	$6,564	$7,519	$5,202	$7,384	$7,986	$3,942	$89,079		
27																
28	**Contractual Obligations (CER)**															
29	Demand (MW)	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,245	1,245	14,900		
30	HLH Energy (MWhr)	359,203	348,099	359,203	359,203	336,029	358,720	347,616	359,203	347,616	359,203	345,886	334,728	4,214,709	480	4,215
31	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Energy (aMW)	483	483	483	483	483	483	483	483	483	483	465	465	5,758	480	
33	Revenue ($ Thousand)													$0		
34																
35	Monthly Trading Floor Committed Sales (MWH)	230,681	427,471	416,605	303,737	507,870	548,761	1,249,208	3,326,556	4,846,063	2,442,282	228,464	80,000	14,607,698	1,663	14,608
36	Monthly Trading Floor Committed Sales ($000)	$15,045	$27,162	$27,931	$23,374	$36,017	$38,669	$62,350	$122,599	$149,277	$159,041	$22,668	$7,780	$691,913		
37																
38	Monthly Trading Floor Balancing Sales (MWH)											39,683	135,931	175,614	20	176
39	Monthly Trading Floor Balancing Sales ($000)											$2,874	$9,196	$12,069		
40																
41	Other Monthly Sales (MWH)	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
42	Other Monthly Sales ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
43																
44	FPS Bookouts	-27,300	-100,034	-75,730	-148,267	-240,800	-5,874	-500,242	-340,512	-370,840	-481,479	-63,728		-2,354,806	-268	-2,355
45	Revenue reversals ($000)	-$1,490	-$5,419	-$4,850	-$9,316	-$15,446	-$193	-$19,806	-$9,990	-$2,750	-$28,784	-$5,083		-$103,128		
46																

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Sep 15, 2008 @ 8:28															
2							Revenue ($ Thousands)									
3							**Fiscal Year 2008**									
4		744	721	744	744	696	743	720	744	720	744	744	720	**Fiscal Year 2008**		
5		432	400	400	416	400	416	416	416	400	416	416	400			
6		312	321	344	328	296	327	304	328	320	328	328	320			
7	**Bulk HUB**	**Oct-07**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Total**	**aMW**	**GWh**
47	**Power Purchases**															
48	**ERE Augmentation Power purchases**	18,395	19,161	21,747	19,743	17,515	17,276	14,243	20,819	24,409	22,232	23,839	17,790	237,168	27	237
49	**ERE Augmentation Purchase Expense**	$583	$629	$704	$577	$545	$506	$423	$482	$496	$543	$647	$558	$6,693		
50	**IOU Power Buyback/Deferred LB CRAC expense**															
51	Expenses ($ Thousand)	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$1,919	$23,024		
52																
53	Renewable HLH (MWH)	27,096	30,992	50,644	50,327	43,967	54,410	52,403	47,357	46,057	37,825	24,493	24,087	489,659	56	490
54	Renewable LLH (MWH)	7,965	7,109	13,017	9,539	9,565	12,560	13,385	12,725	23,398	16,641	22,626	20,206	168,737	19	169
55	Renewable Expense ($000) (included in Program Expense For	$1,486	$1,695	$2,873	$2,769	$2,515	$3,153	$3,028	$2,887	$3,351	$2,684	$2,273	$2,137	$30,850		
56																
57																
58	Power Purchases Bookouts (MWH)	-27,300	-100,034	-75,730	-148,267	-240,800	-5,874	-500,242	-340,512	-370,840	-481,479	-63,728	0	-2,354,806	-268	-2,355
59	Power Purchases Reversals ($000)	-$1,490	-$5,419	-$4,850	-$9,316	-$15,446	-$193	-$19,806	-$9,990	-$2,750	-$28,784	-$5,083	$0	-$103,128		
60																
61	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624															
62	TOTAL HLH Completed: PRE 8/1/00 79620															
63	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
64	TOTAL LLH Completed: PRE 8/1/00 79621															
65																
66	PURCHASE TOTAL HLH Completed: POST 8/1/00															
67	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
68	PURCHASE TOTAL LLH Completed: POST 8/1/00															
69	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
70																
71																
72	Other Committed Power Purchases (MWH)	8,540	5,791	16,278	7,567	5,077	6,142	7,865	15,687	37,278	15,466	15,718	14,486	155,896	18	156
73	Balancing Power Purchases (MWH)											200,566	145,423	345,989	39	346
74	NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 7	524,242	704,103	823,371	523,694	680,529	101,796	1,055,385	453,641	372,204	769,078	282,686	80,000	6,370,728	725	6,371
75	Other Committed Purchase Power Expense ($000)	$468	$307	$872	$482	$313	$396	$622	$661	$788	$447	$497	$448	$6,303		
76	Balancing Purchase Power Expense ($000)											$14,090	$9,894	$23,984		
77	Trading Floor Purchase Power Expense ($000)	$27,296	$42,994	$53,406	$33,239	$42,982	$9,248	$87,375	$27,784	$3,593	$49,649	$23,424	$7,020	$408,010		
78																
79																
80	Residential Exchange Power Purchase															
81	Residential Exchange cost															

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Sep 15, 2008 @ 8:28															
2							Revenue ($ Thousands)									
3							**Fiscal Year 2009**									
4		744	721	744	744	672	743	720	744	720	744	744	720	**Fiscal Year 2009**		
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320			
7	**Bulk HUB**	**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8																
9	**Investor-Owned Utilities Residential Exchange**															
10	Demand (MW)	5388	5688	7179	8143	7444	5789	5801	3794	3352	3833	4456	5381	66248		
11	Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
12	HLH Energy (MWhr)	1,625,361	1,841,325	2,357,576	2,605,870	2,401,028	2,301,903	2,143,900	1,354,851	1,182,225	1,155,773	1,508,699	1,828,050	22,306,562	2,546	22,307
13	LLH Energy (MWhr)	986,431	1,061,893	1,328,339	1,712,588	1,524,682	1,392,875	1,230,499	851,046	647,173	656,823	759,372	1,019,213	13,170,934	1,504	13,171
14	Residential Exchange Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72	43.84		
15																
16	**Residential Exchange Revenue ($000)**	-$110,542	-$143,286	-$191,278	-$200,521	-$185,818	-$167,938	-$126,313	-$72,623	-$57,649	-$70,425	-$98,714	-$130,187	-$1,555,293		
17	LB CRAC True-up/Lookback adjustment	-$5,315	-$5,907	-$7,500	-$8,787	-$7,988	-$7,518	-$6,866	-$4,489	-$3,722	-$3,688	-$4,615	-$5,794	-$72,190		
18																
19	**Direct-Service Industries (IP-02 & FPS)**															
20	IP LBCRAC True-up													$0		
21	**PAC capacity, WNP-3 and other L-T contracts**															
22	Demand (MW)	635	747	770	770	770	688	688	673	708	707	673	650	8,479		
23	HLH Energy (MWhr)	93,775	157,402	171,888	186,584	149,241	114,124	122,788	104,350	114,945	88,264	87,244	87,809	1,478,414	169	1,478
24	LLH Energy (MWhr)	-118,204	-54,937	-47,823	-62,520	-36,787	-64,996	-62,101	-84,007	-69,402	-63,264	-87,244	-107,288	-858,573	-98	-859
25	Energy (aMW)	-33	142	167	167	167	66	84	27	63	34	0	-27	858	71	620
26	Revenue ($ Thousand)	$3,942	$9,082	$9,225	$9,225	$8,795	$6,621	$6,536	$7,501	$3,942	$6,475	$7,986	$3,942	$83,271		
27																
28	**Contractual Obligations (CER)**															
29	Demand (MW)	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,352	1,352	15,154		
30	HLH Energy (MWhr)	345,886	335,193	345,886	345,886	312,413	345,421	334,728	345,886	334,728	345,886	421,922	408,312	4,222,147	482	4,222
31	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Energy (aMW)	465	465	465	465	465	465	465	465	465	465	567	567	5,783	482	
33	Revenue ($ Thousand)													$0		
34																
35	Monthly Trading Floor Committed Sales (MWH)															
36	Monthly Trading Floor Committed Sales ($000)															
37																
38	Monthly Trading Floor Balancing Sales (MWH)	607,034	300,958	563,768	1,446,604	929,466	1,261,473	1,695,821	2,583,674	1,893,830	1,577,552	589,439	375,917	13,825,538	1,578	13,826
39	Monthly Trading Floor Balancing Sales ($000)	$33,396	$17,173	$32,495	$79,255	$51,011	$62,121	$66,462	$77,227	$66,871	$67,513	$27,690	$17,833	$599,046		
40																
41	Other Monthly Sales (MWH)	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
42	Other Monthly Sales ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
43																
44	FPS Bookouts															
45	Revenue reversals ($000)															
46																

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Sep 15, 2008 @ 8:28															
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**
47	**Power Purchases**															
48	**ERE Augmentation Power purchases**	9,326	9,714	11,021	10,008	8,881	8,760	7,238	9,816	10,931	10,904	11,922	8,863	117,384	13	117
49	**ERE Augmentation Purchase Expense**	$294	$320	$371	$297	$277	$252	$202	$232	$235	$275	$339	$273	$3,366		
50	**IOU Power Buyback/Deferred LB CRAC expense**															
51	Expenses ($ Thousand)													$0		
52																
53	Renewable HLH (MWH)	26,590	26,486	24,293	24,063	20,461	38,693	28,678	26,230	27,059	28,177	24,661	24,297	319,687	36	320
54	Renewable LLH (MWH)	19,732	19,209	19,295	16,521	17,703	28,514	23,689	24,297	26,321	25,352	22,458	19,996	263,089	30	263
55	Renewable Expense ($000) (included in Program Expense For	$2,279	$2,288	$2,183	$2,206	$2,128	$3,390	$2,704	$2,654	$2,716	$2,724	$2,398	$2,281	$29,950		
56																
57																
58	Power Purchases Bookouts (MWH)															
59	Power Purchases Reversals ($000)															
60																
61	PURCHASE TOTAL HLH Completed: POST 8/1/00 79624	222,620	215,738	222,620	222,620	201,076	222,320	215,438	222,620	215,438	222,620	222,620	215,438	2,621,167	299	2,621
62	TOTAL HLH Completed: PRE 8/1/00 79620															
63	PURCHASE TOTAL LLH Completed: POST 8/1/00 79625															
64	TOTAL LLH Completed: PRE 8/1/00 79621															
65																
66	PURCHASE TOTAL HLH Completed: POST 8/1/00	$13,402	$12,988	$13,402	$13,402	$12,105	$13,384	$12,970	$13,402	$12,970	$13,402	$13,402	$12,970	$157,799		
67	PURCHASE TOTAL HLH Completed: Pre 8/1/00															
68	PURCHASE TOTAL LLH Completed: POST 8/1/00															
69	PURCHASE TOTAL LLH Completed: Pre 8/1/00															
70																
71																
72	Other Committed Power Purchases (MWH)	13,208	13,405	12,840	14,690	15,604	16,057	19,565	20,978	16,082	8,166	8,418	7,186	166,199	19	166
73	Balancing Power Purchases (MWH)	12,702	68,140	190,389	222,616	281,142	135,375	58,731	19,204	1,061	13,203	100,696	100,411	1,203,671	137	1,204
74	NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 7															
75	Other Committed Purchase Power Expense ($000)	$384	$390	$370	$439	$473	$475	$454	$505	$492	$447	$497	$448	$5,375		
76	Balancing Purchase Power Expense ($000)	$749	$3,765	$11,616	$13,571	$17,767	$7,899	$3,126	$862	$41	$568	$4,832	$4,663	$69,459		
77	Trading Floor Purchase Power Expense ($000)															
78																
79																
80	Residential Exchange Power Purchase	2,611,792	2,903,218	3,685,916	4,318,458	3,925,710	3,694,778	3,374,399	2,205,896	1,829,399	1,812,595	2,268,071	2,847,263	35,477,495	4,050	35,477
81	Residential Exchange cost	$143,335	$159,329	$202,283	$236,997	$215,443	$202,769	$185,187	$121,060	$100,397	$99,475	$124,472	$156,258	$1,947,005		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)								
3								**Fiscal Year 2008**								
4																
5																
6														**Fiscal Year 2008**		
7		**Oct-07**	**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Total**	**aMW**	**GWh**
8																
9	**ANCILLARY SERVICES:**															
10																
11	Federal Remedial Action Scheme	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$396		
12	Synchronous Condensor Operations	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$4,091		
13	Station Service	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$2,089		
14	Redispatch Service	$64	$123	$21	$0	$12	$5	$5	$11	$0	$125	$125	$125	$616		
15	Within hour Balancing Service for Wind Integration															
16	Operating Reserves	$1,946	$2,078	$2,592	$2,808	$2,581	$2,689	$2,789	$2,840	$3,290	$2,629	$2,629	$2,629	$31,501		
17	Regulating Reserves	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$1,279	$15,351		
18	BOR Network/Delivery Facilities	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$554	$6,652		
19	Generation Integration/Energy Imbalance	($246)	$489	$58	($277)	($203)	$399	$481	$649	$1,894	$0	$0	$0	$3,243		
20	**Total Interbusiness Line**	**$4,146**	**$5,072**	**$5,053**	**$4,913**	**$4,772**	**$5,475**	**$5,656**	**$5,881**	**$7,565**	**$5,136**	**$5,136**	**$5,136**	**$63,939**		
21																
22	**RESERVE SERVICES:**															
23	External	$36	$142	$611	$335	$139	$137	$2,031	$156	$81	$275	$275	$275	$4,493		
24	Total External	$36	$142	$611	$335	$139	$137	$2,031	$156	$81	$275	$275	$275	$4,493		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$36**	**$142**	**$611**	**$335**	**$139**	**$137**	**$2,031**	**$156**	**$81**	**$275**	**$275**	**$275**	**$4,493**		
29	**TOTAL Ancillary and Reserves**	**$4,182**	**$5,214**	**$5,664**	**$5,248**	**$4,910**	**$5,611**	**$7,687**	**$6,037**	**$7,646**	**$5,411**	**$5,411**	**$5,411**	**$68,432**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	54,978	37,374	148,102	215,620	206,324	230,778	192,868	157,687	1,399,690	159	1,400
33	Downstream Benefits and Pumping Power $$$	$416	$247	$1,744	$847	$847	$1,072	$873	$888	$915	$800	$792	$765	$10,207		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$7,186	$0	$0	($759)	$6,427		
35	Misc. Generation	$229	$296	$314	$371	$306	$306	$321	$281	$301	$285	$285	$285	$3,580		
36	Energy Efficiency Rev's	$2,026	$32	$1,930	$88	$1,223	$556	$1,289	$11	$438	$1,411	$2,000	$3,000	$14,005		
37	Green Tags and Green Premiums Bulk	$78	$78	$215	$7	$1	$1	$35	$35	$35	$216	$59	$173	$933		
38	Green Premium West	$130	$126	$130	$130	$122	$130	$126	$130	$126	$24	$24	$23	$1,221		
39	Green Premium East	$95	$90	$93	$95	$88	$95	$102	$101	$98	$113	$113	$109	$1,192		
40	4(h)(10)c credit	$7,477	$7,477	$8,000	$8,786	$7,885	$8,497	$8,752	$9,452	$7,685	$9,211	$6,482	$6,482	$96,186		
41	Network Wind Integration&Shaping	$6	$6	$6	$159	$159	$165	$165	$165	$165	$166	$166	$166	$1,490		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$10,841**	**$8,736**	**$12,816**	**$10,865**	**$11,015**	**$11,205**	**$12,047**	**$11,446**	**$17,330**	**$12,610**	**$10,303**	**$10,627**	**$139,841**		

TABLE 3.6.1 REVENUE AT CURRENT RATES

	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Sep 15, 2008 @ 8:28															
2								Revenue ($ Thousands)								
3								**Fiscal Year 2009**								
4																
5																
6														**Fiscal Year 2009**		
7		**Oct-08**	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Total**	**aMW**	**GWh**
8																
9	**ANCILLARY SERVICES:**															
10																
11	Federal Remedial Action Scheme	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$33	$396		
12	Synchronous Condensor Operations	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$341	$4,091		
13	Station Service	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$174	$2,089		
14	Redispatch Service	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$1,500		
15	Within hour Balancing Service for Wind Integration	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$1,594	$19,124		
16	Operating Reserves	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$2,629	$31,551		
17	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		
18	BOR Network/Delivery Facilities	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$616	$7,397		
19	Generation Integration/Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
20	**Total Interbusiness Line**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$6,609**	**$79,306**		
21																
22	**RESERVE SERVICES:**															
23	External	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$3,630		
24	Total External	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$303	$3,630		
25	Interbusiness Line Tx costs for use of AGC															
26	Tx costs for Res. Serv.not included in this total															
27																
28	**TOTAL RESERVE SERVICES**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$303**	**$3,630**		
29	**TOTAL Ancillary and Reserves**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$6,911**	**$82,936**		
30																
31	**OTHER REVENUES**															
32	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	37,374	148,102	215,620	206,324	230,778	187,731	157,687	1,392,661	159	1,393
33	Downstream Benefits and Pumping Power $$$	$731	$710	$710	$710	$711	$714	$733	$762	$782	$800	$792	$765	$8,921		
34	Slice True-Up (and Implementation costs)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,955	$12,955		
35	Misc. Generation	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$285	$3,420		
36	Energy Efficiency Rev's	$1,833	$1,500	$1,667	$1,400	$1,300	$1,300	$1,600	$1,800	$1,600	$2,000	$3,000	$3,000	$22,000		
37	Green Tags and Green Premiums Bulk	$103	$103	$104	$105	$90	$90	$90	$90	$90	$90	$90	$204	$1,250		
38	Green Premium West	$24	$23	$24	$24	$22	$24	$23	$24	$23	$24	$24	$23	$281		
39	Green Premium East	$113	$110	$113	$113	$102	$113	$110	$113	$110	$113	$113	$110	$1,335		
40	4(h)(10)c credit	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$7,373	$88,480		
41	Network Wind Integration&Shaping	$166	$166	$166	$166	$159	$159	$159	$159	$159	$159	$159	$159	$1,933		
42	Colville and Spokane Settlements	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$383	$4,600		
43	LB CRAC True-up															
44	Aluminum Hedging															
45	**TOTAL OTHER REVENUES**	**$11,012**	**$10,654**	**$10,825**	**$10,560**	**$10,425**	**$10,441**	**$10,757**	**$10,990**	**$10,805**	**$11,228**	**$12,220**	**$25,257**	**$145,174**		

TABLE 3.6.2 REVENUE AT PROPOSED RATES REV.

	A	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1		Sep 11, 2008 @ 13:00							Revenues at Proposed Rates								
2									Revenue ($ Thousands)								
3									**Fiscal Year 2009**								
4																	
5																	
6															Fiscal Year 2009		
7		WESTERN HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8			$5,724	$7,745	$8,994	$7,592	$6,532	$6,276	$4,947	$3,838	$2,248	$4,092	$4,900	$5,396	$68,284		
9		**West Hub PF Billing Determinants**	$13,363	$15,554	$18,948	$16,248	$14,522	$13,615	$11,251	$8,220	$7,159	$8,855	$10,994	$10,706	$149,437		
10		**PF Full Service**	$2,838	$3,354	$3,557	$3,327	$3,252	$2,675	$2,172	$1,414	$1,221	$1,568	$1,820	$1,860	$29,057		
11		LLH Energy Flat	267,493	340,904	377,097	380,354	324,016	327,388	280,575	270,874	228,210	244,606	246,832	243,399	3,531,748	403	3532
12		HLH Energy Flat	457,485	499,338	582,847	588,706	515,161	520,647	458,477	400,967	385,931	387,548	410,854	387,604	5,595,565	639	5596
13		PF Flat LLH Energy Rate	$21.40	$22.72	$23.85	$19.96	$20.16	$19.17	$17.63	$14.17	$9.85	$16.73	$19.85	$22.17			
14		PF Flat HLH Energy Rate	$29.21	$31.15	$32.51	$27.60	$28.19	$26.15	$24.54	$20.50	$18.55	$22.85	$26.76	$27.62			
15		LLH Energy Revenue Flat Revenue = 11*13/	$5,724	$7,745	$8,994	$7,592	$6,532	$6,276	$4,947	$3,838	$2,248	$4,092	$4,900	$5,396	$68,284		
16		HLH Energy Revenue Flat Revenue= 12*14/1	$13,363	$15,554	$18,948	$16,248	$14,522	$13,615	$11,251	$8,220	$7,159	$8,855	$10,994	$10,706	$149,437		
17		Demand	1,486	1,644	1,662	1,828	1,758	1,555	1,341	1,055	993	1,045	1,034	1,022	16,423		
18		PF GSP Demand Rate	$1.91	$2.04	$2.14	$1.82	$1.85	$1.72	$1.62	$1.34	$1.23	$1.50	$1.76	$1.82			
19		Demand Revenue = 23*24	$2,838	$3,353	$3,556	$3,327	$3,252	$2,675	$2,172	$1,413	$1,221	$1,567	$1,820	$1,860	$29,054		
20		Load Variance	783,522	897,610	1,019,706	1,028,525	892,992	907,000	795,492	731,181	672,338	691,674	717,910	687,154	9,825,104	1122	9825
21		PF Ld Variance Rate	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46	$0.46			
22		Load Variance Revenue = 26*27/1000	$360	$413	$469	$473	$411	$417	$366	$336	$309	$318	$330	$316	$4,520		
23		Low Density Discount Percent =30/(15+16+2	-2.15%	-2.17%	-2.18%	-2.18%	-2.21%	-2.17%	-2.14%	-2.13%	-2.10%	-2.13%	-2.17%	-2.12%			
24		Low Density Discount	-$480	-$588	-$697	-$602	-$547	-$499	-$402	-$294	-$230	-$316	-$392	-$388	-$5,435		
25	0.2569	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
26		PF Other Energy															
27		PF Other revenues													$0		
28			$6,112	$7,419	$7,867	$7,212	$6,774	$6,246	$5,498	$4,432	$2,774	$5,551	$6,272	$6,779	$72,936		
29		**PF Partial Service**	$16,607	$19,401	$23,412	$19,455	$17,450	$16,783	$14,125	$11,009	$9,435	$11,923	$14,555	$14,603	$188,758		
30		LLH Energy Flat	285,591	326,535	329,856	361,329	336,006	325,845	311,882	312,789	281,604	331,805	315,969	305,767	3,824,978	437	3,825
31		HLH Energy Flat	568,526	622,810	720,145	704,900	619,001	641,802	575,586	537,035	508,643	521,800	543,923	528,725	7,092,896	810	7,093
32		LLH Energy Revenue Flat (40*13)/1000	$6,112	$7,419	$7,867	$7,212	$6,774	$6,246	$5,498	$4,432	$2,774	$5,551	$6,272	$6,779	$72,936		
33		HLH Energy Revenue Flat (41*14)/1000	$16,607	$19,401	$23,412	$19,455	$17,450	$16,783	$14,125	$11,009	$9,435	$11,923	$14,555	$14,603	$188,758		
34		GSP Demand	1,794	1,934	2,064	2,126	2,119	1,913	1,722	1,545	1,362	1,415	1,384	1,425	20,803		
35		Demand Revenue (44*24)	$3,427	$3,944	$4,418	$3,869	$3,919	$3,290	$2,790	$2,071	$1,675	$2,122	$2,435	$2,594	$36,555		
36		Load Variance	1,060,229	1,179,368	1,292,589	1,311,890	1,191,130	1,187,964	1,115,869	1,070,225	1,017,310	1,061,368	1,056,649	1,029,577	13,574,168	1550	13574
37		Load Variance Revenue (45*27)/1000	$488	$543	$595	$603	$548	$546	$513	$492	$468	$488	$486	$474	$6,244		
38	0.0166	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
39		PF Other Energy															
40		PF Other revenues													$0		
41			$8,480	$12,013	$13,862	$11,784	$10,388	$10,462	$6,774	$4,742	$2,747	$5,563	$7,363	$9,599	$103,777		
42		**PF Block Service**	$16,570	$20,418	$25,696	$21,907	$20,298	$19,309	$13,525	$8,945	$7,458	$10,511	$13,389	$15,986	$194,012		
43		LLH Energy Flat	396,271	528,753	581,216	590,400	515,261	545,763	384,226	334,643	278,890	332,526	370,920	432,960	5,291,829	604	5,292
44		HLH Energy Flat	567,259	655,488	790,400	793,728	720,038	738,400	551,158	436,320	402,022	460,013	500,323	578,800	7,193,949	821	7,194
45		LLH Energy Revenue Flat (55*13)/1000	$8,480	$12,013	$13,862	$11,784	$10,388	$10,462	$6,774	$4,742	$2,747	$5,563	$7,363	$9,599	$103,777		
46		LLH Energy Revenue Stepped (56*19)/1000													$0		
47		HLH Energy Revenue Flat (56*14)/1000	$16,570	$20,418	$25,696	$21,907	$20,298	$19,309	$13,525	$8,945	$7,458	$10,511	$13,389	$15,986	$194,012		
48		HLH Energy Revenue Stepped (57*20)/1000													$0		
49		GSP Demand	1,419	1,833	2,015	2,066	2,006	1,906	1,419	1,296	1,149	1,289	1,369	1,499	19,266		
50		Demand Revenue (62*24)	$2,710	$3,739	$4,312	$3,760	$3,711	$3,278	$2,299	$1,737	$1,413	$1,934	$2,409	$2,728	$34,031		
51	0.4824	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
52		PF SUMY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
53		Low Density Discount Percent = 70/(59+60+6	-0.92%	-0.80%	-0.82%	-0.84%	-0.82%	-0.74%	-1.02%	-0.91%	-0.85%	-0.76%	-0.68%	-0.95%			

TABLE 3.6.2 REVENUE AT PROPOSED RATES REV.

	A	B	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1		Sep 11, 2008 @ 13:00							Revenues at Proposed Rates								
2									Revenue ($ Thousands)								
3									Fiscal Year 2009								
4																	
5																	
6															Fiscal Year 2009		
7		WESTERN HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
54		Low-Density Discount	-$254	-$290	-$362	-$313	-$281	-$246	-$231	-$140	-$98	-$136	-$158	-$269	-$2,779		
55		PF Other Energy													0		
56		PF Block Other Revenues													$0		
57										$1,389	$1,638	$2,500	$2,563		$8,090		
58		**Irrigation Mitigation LLH**	0	0	0	0	0	0	0	28,360	39,538	44,976	39,178	0	152,052	17	152
59		**Irrigation Mitigation HLH**	0	0	0	0	0	0	0	48,163	67,322	76,479	66,709	0	258,673	30	259
60		**Irrigation Mitigation Revenues**	$0	$0	$0	$0	$0	$0	$0	$735	$734	$1,420	$1,607	$0	$4,497		
61															$0		
62																	
63		**TAC LLH**													0	-	-
64		**TAC HLH**													0	-	-
65		**TAC Demand**													0		
66		**TAC Revenues**													$0		
67																	
68		PF SLICE	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$34,660	$415,917		
69		Percent of SLICE	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.5085%	18.51%	1754	
70		Slice rate	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873	$1,873			
71		Slice Charges ($000) 90*91	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$34,663	$415,951		
72		Monetary Benefits to IOUs ($000) 90*93	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
73	0.818	LBCRAC True-up/Lookback Adjust	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
74		LDD Percentage	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%	-1.12%			
75		Low-Density Discount	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$389	-$4,671		
76		Slice Other															
77		West Hub FPS (Pre-Subscription) Sales															
78		LLH Energy Full Service	6,552	7,077	6,888	6,888	6,048	6,867	6,384	7,224	6,384	6,888	6,888	6,720	80,808	9	81
79		LLH Energy Revenue	$142	$161	$163	$142	$125	$137	$119	$115	$79	$124	$141	$150	$1,600		
80		HLH Energy Full Service	9,072	8,064	8,736	8,736	8,064	8,736	8,736	8,400	8,736	8,736	8,736	8,400	103,152	12	103
81		HLH Energy Revenue	$255	$239	$268	$234	$220	$224	$212	$176	$170	$200	$228	$225	$2,650		
82		GSP Demand	17	17	17	17	17	17	17	17	17	17	17	17	204		
83		Demand Revenue	$65	$69	$73	$62	$63	$58	$55	$46	$42	$51	$60	$62	$706		
84		Load Variance	15,624	15,141	15,624	15,624	14,112	15,603	15,120	15,624	15,120	15,624	15,624	15,120	183960	21	184
85		Load Variance Revenue	$7	$7	$7	$7	$6	$7	$7	$7	$7	$7	$7	$7	$85		
86		Low-Density Discount													$0		
87		LT SURPLUS FB CRAC															
88		Netrwork Wind Integration Service													$0		
89		Other Pre-Subscription revenues													$0		
90																	
91		Public Agency Residential Exchange															
92		Monthly Energy Flat													0	-	-
93		Monthly Energy Flat Rate	42.32	49.35	51.89	46.43	47.33	45.45	37.43	32.92	31.51	38.85	43.52	45.72			
94		Monthly Energy Revenue (40*14)/1000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
95		GSP Demand													0		
96		GSP Demand Rate	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85			
97		Demand Revenue (43*24)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
98		**Total**	$110,687	$128,415	$145,855	$130,033	$121,665	$116,853	$98,295	$82,153	$71,884	$88,550	$100,720	$105,101	$1,300,212		

TABLE 3.7
PS Monthly Revenue Forecast for Ancillary Reserve Services

	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
GENERATION INPUTS FOR ANCILLARY SERVICES:										
INTERBUSINESS LINE										
Re-Dispatch for NT Tx	$125,000	$125,000	$125,000	$125,000	$125,000	$125,000	$125,000	$125,000	$125,000	$125,000
Energy Imbalance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Federal RAS for Generation Dropping	$33,006	$33,006	$33,006	$33,006	$33,006	$33,006	$33,006	$33,006	$33,006	$33,006
Generation Supplied Reactive & Voltage Ctrl	$340,925	$340,925	$340,925	$340,925	$340,925	$340,925	$340,925	$340,925	$340,925	$340,925
Station Service	$174,048	$174,048	$174,048	$174,048	$174,048	$174,048	$174,048	$174,048	$174,048	$174,048
Regulating Reserve	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500	$1,096,500
Operating Reserves - Spinning & Supplemental	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210	$2,629,210
COE/BOR Network/Delivery Facilities	$616,417	$616,417	$616,417	$616,417	$616,417	$616,417	$616,417	$616,417	$616,417	$616,417
Within-Hour Balancing Service for Wind Integration	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693	$1,593,693
TOTAL ANCILLARY SERVICES	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**	**$5,015,105**
RESERVE SERVICES:										
EXTERNAL										
Reserve Sales Outside BPAT Control Area	$302,500	$302,500	$302,500	$302,500	$302,500	$302,500	$302,500	$302,500	$302,500	$302,500
TOTAL RESERVE SERVICES	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**	**$302,500**
TOTAL ANCILLARY & RESERVE SERVICES$_{(11+15)}$	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**	**$5,317,605**

TABLE 3.7
PS Monthly Revenue Forecast for Ancillary Reserve Services

	Aug-09	Sep-09	**FY09 Net Revenue**
GENERATION INPUTS FOR ANCILLARY SERVICES:			
INTERBUSINESS LINE			
Re-Dispatch for NT Tx	$125,000	$125,000	$1,500,000
Energy Imbalance	$0	$0	$0
Federal RAS for Generation Dropping	$33,006	$33,006	$396,071
Generation Supplied Reactive & Voltage Ctrl	$340,925	$340,925	$4,091,096
Station Service	$174,048	$174,048	$2,088,577
Regulating Reserve	$1,096,500	$1,096,500	$13,158,000
Operating Reserves - Spinning & Supplemental	$2,629,210	$2,629,210	$31,550,520
COE/BOR Network/Delivery Facilities	$616,417	$616,417	$7,397,000
Within-Hour Balancing Service for Wind Integration	$1,593,693	$1,593,693	$19,124,320
TOTAL ANCILLARY SERVICES	**$5,015,105**	**$5,015,105**	**$79,305,584**
RESERVE SERVICES:			
EXTERNAL			
Reserve Sales Outside BPAT Control Area	$302,500	$302,500	$3,630,000
TOTAL RESERVE SERVICES	**$302,500**	**$302,500**	**$3,630,000**
TOTAL ANCILLARY & RESERVE SERVICES$_{(11+15)}$	**$5,317,605**	**$5,317,605**	**$82,935,584**

TABLE 3.8.1

Total Sales (aMW) For FY 2009

Wtr Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Ann Avg
1929	0	177	0	0	0	361	0	0	2,620	1,342	0	181	389
1930	750	421	0	0	0	0	315	0	1,731	1,325	54	212	401
1931	562	367	0	0	0	0	185	145	1,889	1,388	252	396	433
1932	114	176	0	0	0	834	3,812	5,259	2,920	1,757	279	579	1,315
1933	292	50	143	2,737	1,454	440	2,225	3,104	2,673	2,419	1,959	729	1,520
1934	1,167	1,521	2,886	2,915	2,709	3,418	3,656	3,637	2,518	1,578	0	189	2,181
1935	485	0	0	2,456	3,098	9	1,665	2,957	1,743	2,503	794	178	1,314
1936	599	335	0	0	0	204	1,747	4,383	3,127	1,231	232	49	997
1937	560	390	0	0	0	0	126	363	1,974	830	413	272	411
1938	607	181	14	2,527	909	1,907	3,599	4,819	3,338	1,987	3	525	1,705
1939	774	308	0	257	0	417	2,277	3,952	1,094	1,162	0	0	860
1940	816	316	436	0	0	2,843	2,962	2,412	2,160	579	0	225	1,067
1941	562	146	239	282	0	435	37	85	2,156	1,129	271	709	505
1942	143	66	958	2,141	0	0	1,319	2,123	3,402	3,068	1,043	264	1,220
1943	749	182	0	2,138	2,434	2,668	3,715	4,639	2,819	2,501	487	0	1,858
1944	395	311	0	28	0	0	0	130	1,478	699	62	473	298
1945	193	180	0	0	0	0	0	2,670	3,452	721	50	125	617
1946	394	298	370	1,260	772	2,865	4,060	4,584	3,179	2,938	642	425	1,822
1947	521	246	2,485	3,074	2,902	3,519	2,921	4,025	3,213	2,946	363	384	2,216
1948	2,390	1,495	1,582	3,788	1,217	1,727	3,137	5,015	2,564	3,118	1,922	668	2,399
1949	925	236	124	492	138	3,341	3,738	5,069	3,107	679	0	0	1,495
1950	599	19	0	2,294	3,013	4,341	3,996	3,955	2,343	2,947	1,143	474	2,090
1951	1,507	1,149	3,012	3,562	2,981	4,305	3,847	4,871	3,056	3,011	1,115	317	2,732
1952	1,904	419	1,664	3,820	1,814	1,034	4,455	5,028	3,471	2,393	382	101	2,211
1953	630	294	0	127	2,936	1,029	860	3,944	2,843	3,136	759	389	1,403
1954	921	292	809	1,880	3,563	1,725	2,692	4,524	2,289	2,327	3,232	2,254	2,201
1955	948	489	1,129	0	0	110	220	2,226	2,472	2,358	1,905	211	1,016
1956	1,102	979	3,072	3,947	3,525	4,294	3,708	4,692	2,425	2,946	984	450	2,678
1957	1,081	182	506	1,965	0	2,504	3,571	5,216	2,714	1,717	0	242	1,654
1958	378	286	0	1,110	1,776	1,582	3,179	5,178	3,178	1,577	216	213	1,552
1959	865	385	2,300	3,783	3,373	2,727	3,311	3,919	2,505	1,967	916	2,404	2,365
1960	2,906	2,404	2,567	3,008	1,018	1,984	3,895	3,635	3,151	2,480	171	386	2,309
1961	765	226	0	2,161	1,545	2,488	2,959	4,352	2,575	2,211	478	75	1,656
1962	353	358	0	2,865	0	132	3,631	4,155	3,056	1,147	303	133	1,350
1963	1,339	552	2,069	3,141	648	0	1,612	3,496	3,449	2,757	843	376	1,701
1964	420	319	0	1,662	0	0	1,822	3,786	2,576	2,796	1,542	974	1,335
1965	1,425	386	3,068	3,998	3,247	4,148	3,380	5,010	3,181	2,166	1,279	455	2,649
1966	1,056	288	182	2,565	0	0	3,225	3,066	2,576	2,679	743	108	1,384
1967	517	210	124	3,539	3,606	2,705	889	3,243	2,530	3,235	1,105	485	1,843
1968	842	180	350	2,911	1,824	1,676	370	2,402	2,961	3,451	1,434	1,458	1,658
1969	1,538	1,124	1,733	3,850	3,832	3,183	3,738	4,731	2,934	3,197	268	246	2,526
1970	937	336	0	1,253	967	933	1,124	3,441	3,326	1,842	21	71	1,189
1971	613	171	0	3,922	3,410	4,246	4,187	4,885	2,645	2,843	2,127	660	2,474
1972	1,093	308	482	3,888	3,724	3,403	3,277	4,811	2,348	2,394	2,778	700	2,431
1973	943	250	752	1,948	0	0	0	1,400	2,001	1,163	0	0	712
1974	523	0	1,518	3,193	2,721	4,088	3,563	4,629	2,386	2,416	2,048	525	2,304
1975	187	245	0	1,490	666	2,384	1,177	4,459	2,934	2,802	853	721	1,502
1976	1,546	1,236	3,260	3,425	3,336	3,347	4,156	4,977	3,088	2,812	3,414	3,074	3,140
1977	860	260	0	0	0	0	0	65	875	633	65	331	258
1978	0	120	53	1,815	0	1,533	3,421	4,168	2,474	2,714	666	1,692	1,563
Average	**816**	**417**	**758**	**1,944**	**1,383**	**1,698**	**2,355**	**3,473**	**2,630**	**2,120**	**792**	**522**	**1,578**
Total Hrs	744	721	744	744	672	743	720	744	720	744	744	720	**8760**
HLH Hrs	432	384	416	416	384	416	416	400	416	416	416	400	4912
LLH Hrs	312	337	328	328	288	327	304	344	304	328	328	320	3848

TABLE 3.8.1

Total Revenue ($Thousand) For FY 2009

Wtr Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
1929	0	7,638	0	0	0	14,942	0	0	76,459	45,691	0	6,443	151,173
1930	32,781	18,437	0	0	0	0	10,679	0	61,825	45,189	2,057	7,573	178,540
1931	24,417	15,856	0	0	0	0	6,045	5,836	66,444	47,819	9,460	14,017	189,895
1932	5,100	7,647	0	0	0	34,579	112,766	106,389	72,873	58,363	10,349	20,628	428,693
1933	12,840	2,181	6,581	113,526	59,935	18,093	69,919	95,415	63,998	72,108	69,398	25,308	609,302
1934	45,351	59,007	119,669	113,460	100,247	127,248	99,705	88,984	70,107	53,198	0	6,732	883,708
1935	21,273	0	0	101,747	108,585	358	56,285	89,150	48,311	80,756	28,964	6,336	541,766
1936	26,157	14,406	0	0	0	8,271	51,439	97,941	78,306	42,530	8,584	1,758	329,391
1937	24,206	16,756	0	0	0	0	4,097	12,983	67,448	28,879	15,336	9,731	179,436
1938	26,415	7,846	649	107,522	37,248	72,958	105,064	90,070	88,445	65,626	97	18,616	620,557
1939	33,598	13,481	0	11,984	0	17,294	67,778	100,167	34,178	40,425	0	0	318,907
1940	35,259	13,665	19,873	0	0	106,750	93,656	79,069	64,662	20,222	0	8,013	441,170
1941	24,629	6,350	11,069	12,980	0	18,279	1,272	3,548	75,705	39,229	10,210	24,895	228,165
1942	6,350	2,896	43,636	88,969	0	0	41,760	65,926	84,802	98,275	38,951	9,346	480,911
1943	32,332	7,824	0	91,446	88,090	96,591	86,399	91,390	66,473	79,567	17,987	0	658,099
1944	17,105	13,611	0	1,306	0	0	0	5,162	53,664	24,515	2,398	16,751	134,512
1945	8,516	7,896	0	0	0	0	0	85,260	84,811	25,043	1,910	4,454	217,892
1946	17,233	12,829	16,951	55,863	32,740	98,921	114,758	84,289	79,321	91,136	23,564	15,043	642,649
1947	22,399	10,616	100,868	132,558	106,857	125,762	89,460	93,740	84,593	94,990	13,294	13,658	888,793
1948	87,295	58,069	69,880	145,452	46,677	66,987	99,298	93,224	55,984	97,453	67,599	23,320	911,240
1949	39,628	10,089	5,738	22,605	5,871	120,846	101,907	92,991	73,106	23,420	0	0	496,200
1950	25,823	806	0	101,972	110,625	152,760	102,308	85,074	54,987	90,991	41,051	16,950	783,346
1951	58,529	45,043	126,378	135,588	101,795	145,968	97,212	84,487	76,760	90,797	40,378	11,385	1,014,319
1952	71,128	17,921	73,439	154,411	65,178	43,269	112,950	83,994	75,841	77,897	14,356	3,612	793,996
1953	27,488	12,812	0	5,880	112,309	41,909	28,223	92,752	63,793	95,293	27,853	13,838	522,150
1954	39,043	12,595	36,791	84,434	125,338	68,083	80,832	94,243	55,682	71,007	104,670	72,696	845,414
1955	39,503	20,724	50,770	0	0	4,557	6,841	73,566	57,966	67,472	65,041	7,493	393,932
1956	43,558	38,915	125,714	154,015	133,669	160,068	91,483	81,099	54,361	92,425	35,061	15,844	1,026,213
1957	44,566	7,879	23,197	86,582	0	89,791	98,940	89,004	62,824	58,374	0	8,584	569,740
1958	16,506	12,391	0	46,186	69,896	65,319	98,022	93,593	73,512	53,063	8,167	7,615	544,269
1959	36,881	16,340	99,648	148,252	124,535	97,570	95,644	90,780	61,043	62,984	33,365	78,209	945,251
1960	109,657	92,286	107,251	126,136	40,252	74,604	96,916	98,726	81,133	80,522	6,363	13,662	927,508
1961	33,124	9,656	0	90,268	55,965	93,122	92,386	97,221	64,163	73,046	17,679	2,665	629,296
1962	15,588	15,422	0	125,499	0	5,405	107,394	99,955	75,282	38,766	11,150	4,752	499,213
1963	54,331	23,653	89,667	131,136	27,519	0	49,747	109,771	88,711	88,640	30,594	13,315	707,084
1964	18,199	13,683	0	71,466	0	0	57,389	99,583	58,866	86,037	54,661	33,623	493,507
1965	55,947	16,825	128,024	153,679	109,035	146,621	97,176	89,780	80,836	69,936	45,114	16,126	1,009,100
1966	43,920	12,338	8,444	107,301	0	0	98,001	92,401	71,333	85,367	27,644	3,842	550,590
1967	22,426	9,154	5,699	139,405	121,916	91,141	29,391	91,910	56,148	99,490	39,743	17,070	723,494
1968	35,285	7,794	16,187	118,265	71,084	64,125	12,759	81,816	79,174	106,623	50,355	49,526	692,994
1969	59,160	44,598	76,606	146,320	146,235	112,268	92,388	79,262	73,600	102,420	9,971	8,683	951,512
1970	39,579	14,400	0	55,628	39,879	38,415	36,263	90,627	77,291	61,314	779	2,535	456,710
1971	26,392	7,385	0	155,247	123,437	149,023	110,729	85,105	58,690	87,041	72,460	23,180	898,689
1972	44,364	13,326	22,154	155,441	136,351	117,214	84,586	87,367	48,513	70,936	90,777	24,433	895,463
1973	39,749	10,737	34,600	81,557	0	0	0	49,918	57,609	39,659	0	0	313,829
1974	22,406	0	66,719	114,139	99,739	144,129	86,681	79,286	53,114	71,007	71,192	18,776	827,189
1975	8,190	10,616	0	64,824	27,290	91,156	38,247	91,798	67,614	85,961	30,494	25,254	541,443
1976	59,266	47,772	136,097	130,262	122,258	117,317	103,520	90,771	67,227	83,276	108,595	96,992	1,163,352
1977	36,282	11,299	0	0	0	0	0	2,734	29,631	22,294	2,281	11,732	116,252
1978	0	5,170	2,427	79,456	0	64,328	104,775	93,198	66,316	88,563	24,532	56,658	585,424
Average	**33,396**	**17,173**	**32,495**	**79,255**	**51,011**	**62,121**	**66,462**	**77,227**	**66,871**	**67,513**	**27,690**	**17,833**	**599,046**

TABLE 3.8.2
Total Purchases (aMW) For FY 2009

Wtr Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Ann Avg
1929	115	153	568	663	1,873	0	559	314	0	0	301	225	387
1930	0	63	417	1,970	620	468	0	230	0	0	304	184	356
1931	0	83	521	1,903	1,757	597	58	151	0	0	233	117	445
1932	10	155	1,095	1,954	1,819	0	0	0	0	0	224	52	435
1933	0	157	168	0	0	0	0	0	0	0	0	0	27
1934	0	0	0	0	0	0	0	0	0	0	655	197	72
1935	0	213	830	0	0	367	0	0	0	0	4	223	138
1936	0	84	717	1,593	1,212	0	0	0	0	0	131	254	328
1937	0	69	461	2,026	1,528	522	164	0	0	90	151	153	425
1938	0	117	121	0	0	0	0	0	0	0	326	51	52
1939	0	86	927	214	1,357	0	0	0	67	0	628	349	296
1940	0	88	0	825	394	0	0	0	0	196	796	176	206
1941	0	137	96	245	1,525	0	342	331	0	0	224	0	233
1942	2	153	81	0	257	1,146	0	0	0	0	0	163	150
1943	0	102	329	0	0	0	0	0	0	0	0	305	61
1944	0	84	614	314	1,708	1,135	625	36	0	155	138	89	400
1945	0	161	957	1,823	1,133	758	705	0	0	82	303	223	510
1946	0	83	0	0	0	0	0	0	0	0	5	81	14
1947	0	80	0	0	0	0	0	0	0	0	22	136	20
1948	0	0	0	0	0	0	0	0	0	0	0	23	2
1949	0	111	147	208	1	0	0	0	0	114	574	563	144
1950	0	202	367	0	0	0	0	0	0	0	0	41	51
1951	0	0	0	0	0	0	0	0	0	0	0	161	13
1952	0	39	0	0	0	0	0	0	0	0	17	231	24
1953	0	113	894	291	0	0	0	0	0	0	0	130	121
1954	0	82	0	0	0	0	0	0	0	0	0	0	7
1955	0	87	0	346	641	24	27	0	0	0	0	194	106
1956	0	0	0	0	0	0	0	0	0	0	0	69	6
1957	0	115	154	0	1,105	0	0	0	0	0	184	188	138
1958	0	95	355	11	0	0	0	0	0	0	210	208	74
1959	0	102	0	0	0	0	0	0	0	0	0	0	8
1960	0	0	0	0	0	0	0	0	0	0	82	81	14
1961	0	126	306	0	0	0	0	0	0	0	22	273	61
1962	0	46	233	0	86	39	0	0	0	0	183	240	69
1963	0	41	0	0	0	624	0	0	0	0	0	144	68
1964	0	59	184	0	193	944	0	0	0	0	0	0	115
1965	0	58	0	0	0	0	0	0	0	0	0	84	12
1966	0	122	243	0	465	466	0	0	0	0	0	243	126
1967	0	125	109	0	0	0	0	0	0	0	0	77	26
1968	0	157	154	0	0	0	0	0	0	0	0	0	26
1969	0	0	0	0	0	0	0	0	0	0	3	157	13
1970	0	89	393	33	0	0	0	0	0	0	222	273	85
1971	0	153	243	0	0	0	0	0	0	0	0	0	33
1972	0	60	75	0	0	0	0	0	0	0	0	2	11
1973	0	89	16	0	1,333	884	768	0	0	0	750	414	347
1974	0	239	0	0	0	0	0	0	0	0	0	34	22
1975	0	108	408	0	0	0	0	0	0	0	0	6	44
1976	0	0	0	0	0	0	0	0	0	0	0	0	0
1977	0	109	546	541	1,737	1,135	831	229	7	250	0	157	453
1978	727	130	66	0	175	0	0	0	0	0	74	0	98
Average	**17**	**95**	**256**	**299**	**418**	**182**	**82**	**26**	**1**	**18**	**135**	**139**	**137**
Total Hrs	744	721	744	744	672	743	720	744	720	744	744	720	**8760**
HLH Hrs	432	384	416	416	384	416	416	400	416	416	416	400	4912
LLH Hrs	312	337	328	328	288	327	304	344	304	328	328	320	3848

TABLE 3.8.2

Total Expenses ($Thousand) For FY 2009

Wtr Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
1929	4,768	6,177	25,906	29,181	79,935	0	21,469	12,297	0	0	10,460	7,495	197,688
1930	0	2,522	18,964	92,328	25,630	20,317	0	8,870	0	0	10,550	6,086	185,268
1931	0	3,350	23,899	88,457	74,991	26,343	2,232	4,527	0	0	8,116	3,856	235,771
1932	408	6,359	50,566	90,010	76,979	0	0	0	0	0	7,716	1,709	233,746
1933	0	6,187	7,273	0	0	0	0	0	0	0	0	0	13,461
1934	0	0	0	0	0	0	0	0	0	0	24,240	6,511	30,751
1935	0	8,351	38,080	0	0	15,892	0	0	0	0	138	7,360	69,822
1936	0	3,394	32,909	72,707	53,571	0	0	0	0	0	4,516	8,596	175,693
1937	0	2,802	20,855	93,992	64,740	22,383	6,330	0	0	2,817	5,097	5,089	224,104
1938	0	4,503	5,308	0	0	0	0	0	0	0	11,201	1,673	22,685
1939	0	3,479	42,569	8,604	60,565	0	0	0	1,854	0	22,846	11,952	151,870
1940	0	3,592	0	36,429	16,174	0	0	0	0	6,252	29,273	5,923	97,643
1941	0	5,612	4,241	10,041	67,483	0	13,202	9,683	0	0	7,794	0	118,056
1942	93	6,307	3,395	0	10,286	51,173	0	0	0	0	0	5,307	76,562
1943	0	4,073	14,852	0	0	0	0	0	0	0	0	10,303	29,228
1944	0	3,304	27,954	13,262	72,086	49,215	23,880	1,048	0	5,027	4,764	2,971	203,512
1945	0	6,563	44,336	84,460	47,446	32,811	27,038	0	0	2,588	10,464	7,452	263,158
1946	0	3,329	0	0	0	0	0	0	0	0	158	2,678	6,165
1947	0	3,120	0	0	0	0	0	0	0	0	747	4,551	8,418
1948	0	0	0	0	0	0	0	0	0	0	0	733	733
1949	0	4,400	6,482	8,752	29	0	0	0	0	3,509	20,784	19,498	63,453
1950	0	8,084	16,274	0	0	0	0	0	0	0	0	1,299	25,657
1951	0	0	0	0	0	0	0	0	0	0	0	5,252	5,252
1952	0	1,510	0	0	0	0	0	0	0	0	570	7,673	9,752
1953	0	4,537	41,123	11,361	0	0	0	0	0	0	0	4,234	61,255
1954	0	3,198	0	0	0	0	0	0	0	0	0	0	3,198
1955	0	3,282	0	14,460	26,157	1,042	1,040	0	0	0	0	6,359	52,340
1956	0	0	0	0	0	0	0	0	0	0	0	2,259	2,259
1957	0	4,471	6,607	0	44,848	0	0	0	0	0	6,439	6,350	68,716
1958	0	3,788	16,092	394	0	0	0	0	0	0	7,227	6,919	34,421
1959	0	3,888	0	0	0	0	0	0	0	0	0	0	3,888
1960	0	0	0	0	0	0	0	0	0	0	2,794	2,703	5,497
1961	0	4,966	13,816	0	0	0	0	0	0	0	762	9,204	28,749
1962	0	1,847	10,300	0	3,656	1,700	0	0	0	0	6,305	8,008	31,817
1963	0	1,575	0	0	0	26,375	0	0	0	0	0	4,705	32,654
1964	0	2,273	8,184	0	7,719	40,379	0	0	0	0	0	0	58,554
1965	0	2,280	0	0	0	0	0	0	0	0	0	2,688	4,969
1966	0	4,883	10,775	0	19,015	19,869	0	0	0	0	0	8,102	62,643
1967	0	4,990	4,691	0	0	0	0	0	0	0	0	2,520	12,200
1968	0	6,204	6,629	0	0	0	0	0	0	0	0	0	12,833
1969	0	0	0	0	0	0	0	0	0	0	109	5,204	5,313
1970	0	3,509	17,876	1,185	0	0	0	0	0	0	7,691	9,123	39,384
1971	0	6,110	10,850	0	0	0	0	0	0	0	0	0	16,960
1972	0	2,316	3,197	0	0	0	0	0	0	0	0	55	5,568
1973	0	3,509	676	0	56,075	38,287	29,421	0	0	0	28,342	14,196	170,505
1974	0	9,752	0	0	0	0	0	0	0	0	0	1,073	10,825
1975	0	4,311	18,426	0	0	0	0	0	0	0	0	209	22,947
1976	0	0	0	0	0	0	0	0	0	0	0	0	0
1977	0	4,321	24,813	22,926	73,808	49,162	31,695	6,674	181	8,219	0	5,258	227,059
1978	32,199	5,236	2,869	0	7,147	0	0	0	0	0	2,512	0	49,963
Average	**749**	**3,765**	**11,616**	**13,571**	**17,767**	**7,899**	**3,126**	**862**	**41**	**568**	**4,832**	**4,663**	**69,459**

TABLE 3.8.3
AUGMENTATION PURCHASE EXPENSE

Price = Weighted average annual purchase price for 1937 from 50 WY run.				
	MW	**Hours**	**$/MWh**	**Exp. ($ Thousand)**
FY 2009	299	8,760	60.20	157,799
FY 2010	297	8,760	59.84	155,648
FY 2011	509	8,760	61.53	274,260
FY 2012	184	8,784	62.68	101,541
FY 2013	345	8,760	64.66	195,624

TABLE 3.10						
Low Density Discount Revenue Example						
	Demand Full Day	Energy HLH	Energy LLH	Load Variance Full Day	Low Density Discount - non-slice Full Day	Calculated LDD (7% LDD)
200810	$28,997.18	$144,918.51	$63,315.44	$3,660.89	($16,862.44)	($16,862.44)
200811	$30,375.18	$157,396.73	$78,633.38	$3,935.02	($18,923.82)	($18,923.82)
200812	$31,644.88	$179,952.64	$90,509.00	$4,311.78	($21,449.28)	($21,449.28)
200901	$28,909.95	$153,091.77	$74,508.09	$4,288.41	($18,255.88)	($18,255.88)
200902	$30,957.96	$143,931.87	$66,040.26	$3,874.46	($17,136.32)	($17,136.32)
200903	$24,811.50	$129,916.37	$59,756.85	$3,737.41	($15,275.55)	($15,275.55)
200904	$18,600.88	$100,987.07	$45,378.14	$3,091.86	($11,764.06)	($11,764.06)
200905	$15,517.60	$87,155.73	$39,214.62	$3,244.64	($10,159.28)	($10,159.28)
200906	$12,965.00	$75,628.51	$23,587.35	$2,990.09	($8,061.97)	($8,061.97)
200907	$16,270.02	$91,819.21	$42,885.27	$3,041.88	($10,781.15)	($10,781.15)
200908	$19,117.20	$112,233.63	$47,430.71	$3,043.30	($12,727.74)	($12,727.74)
200909	$17,854.35	$104,203.93	$54,046.29	$2,870.50	($12,528.25)	($12,528.25)

4. ADDITIONAL RATE DESIGN TABLES

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Table 4.1

Settlement Rates

See Table 2.7

In WP-07-FS-BPA-13A

4.2 OMIT

Table 4.3 Load Variance Documentation

		Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02
Forecast	**HLH**	1,253,844	1,373,433	1,583,675	1,632,359	1,399,762	1,390,500	1,281,042	1,258,743	1,216,327	1,296,912	1,296,488	1,210,766	1,297,365
	LLH	782,653	887,435	1,030,294	1,055,044	921,747	928,549	830,777	814,347	791,970	801,684	808,463	750,819	817,509
Forecast Error	**HLH**	26,080	28,567	32,940	33,953	29,115	28,922	26,646	26,182	25,300	26,976	26,967	25,184	26,985
2.08%	**LLH**	16,279	18,459	21,430	21,945	19,172	19,314	17,280	16,938	16,473	16,675	16,816	15,617	17,004
(Cost)/Benefit of Error	**HLH**	($677,049)	($809,444)	($975,165)	($881,332)	($754,469)	($643,515)	($787,231)	($591,754)	($354,952)	($666,317)	($727,841)	($745,703)	($575,253)
	LLH	($431,726)	($424,127)	($523,107)	($534,409)	($484,124)	($480,295)	($439,772)	($243,225)	($132,748)	($337,011)	($397,215)	($365,076)	($393,969)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls		**Oct-06**	**Nov-06**	**Dec-06**	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**
07 Forecast	**HLH**	1,546,494	1,617,952	1,803,317	1,872,207	1,628,310	1,647,798	1,522,276	1,531,407	1,519,304	1,626,014	1,606,788	1,439,891	1,579,576
07 Forecast	**LLH**	999,101	1,138,794	1,286,376	1,274,592	1,134,900	1,128,951	1,019,260	1,061,358	1,040,973	1,088,970	1,053,789	985,769	1,009,673
Load Growth	**HLH**	0	0	0	0	0	0	0	0	0	0	0	0	33,081
	LLH	0	0	0	0	0	0	0	0	0	0	0	0	10,572
(Cost)/Benefit of Load Gro	**HLH**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($705,209)
	LLH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($244,940)
Total Retail Load Forecast	**MWh**	2,545,596	2,756,746	3,089,693	3,146,799	2,763,211	2,776,749	2,541,536	2,592,764	2,560,277	2,714,984	2,660,576	2,425,660	2,589,249

Table 4.3 Load Variance Documentation

		Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03
Forecast	**HLH**	1,405,364	1,613,580	1,646,314	1,407,647	1,404,957	1,304,052	1,269,984	1,222,252	1,307,495	1,316,568	1,218,224	1,279,186	1,362,818
	LLH	913,949	1,054,108	1,066,095	926,510	940,914	843,791	819,294	794,939	807,304	827,713	746,928	808,112	900,284
Forecast Error	**HLH**	29,232	33,562	34,243	29,279	29,223	27,124	26,416	25,423	27,196	27,385	25,339	26,607	28,347
2.08%	**LLH**	19,010	21,925	22,175	19,271	19,571	17,551	17,041	16,535	16,792	17,216	15,536	16,809	18,726
(Cost)/Benefit of Error	**HLH**	($746,364)	($944,687)	($656,320)	($561,742)	($501,391)	($388,574)	($375,816)	($417,431)	($443,537)	($483,115)	($527,265)	($359,695)	($525,536)
	LLH	($416,011)	($510,486)	($414,185)	($355,295)	($364,204)	($254,629)	($216,403)	($189,229)	($231,421)	($327,538)	($259,447)	($286,968)	($306,983)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls		**Nov-07**	**Dec-07**	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**
07 Forecast	**HLH**	1,646,941	1,836,315	1,905,499	1,669,534	1,669,669	1,554,425	1,557,246	1,540,954	1,659,846	1,631,049	1,470,239	1,597,544	1,657,549
07 Forecast	**LLH**	1,157,045	1,307,318	1,295,052	1,160,099	1,151,155	1,029,418	1,076,065	1,057,572	1,100,345	1,071,062	995,079	1,021,350	1,177,274
Load Growth	**HLH**	28,989	32,997	33,292	41,224	21,871	32,150	25,839	21,650	33,832	24,261	30,349	51,050	39,596
	LLH	18,251	20,943	20,460	25,199	22,204	10,157	14,708	16,599	11,375	17,274	9,310	22,248	38,480
(Cost)/Benefit of Load Gro	**HLH**	($740,162)	($928,784)	($638,088)	($790,910)	($375,243)	($460,564)	($367,613)	($355,480)	($551,768)	($428,016)	($631,503)	($690,132)	($734,100)
	LLH	($399,402)	($487,605)	($382,151)	($464,579)	($413,194)	($147,365)	($186,767)	($189,966)	($156,762)	($328,628)	($155,477)	($379,835)	($630,819)
Total Retail Load Forecast	**MWh**	2,803,986	3,143,633	3,200,551	2,829,633	2,820,824	2,583,843	2,633,311	2,598,526	2,760,191	2,702,112	2,465,319	2,618,894	2,834,822

Table 4.3 Load Variance Documentation

		Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04
Forecast	**HLH**	1,596,159	1,641,654	1,412,924	1,432,170	1,294,547	1,278,766	1,242,685	1,351,551	1,346,982	1,232,818	1,304,583
	LLH	1,040,176	1,062,974	946,580	955,434	854,508	840,390	800,821	835,724	841,493	767,889	833,762
Forecast Error	**HLH**	33,200	34,146	29,389	29,789	26,927	26,598	25,848	28,112	28,017	25,643	27,135
2.08%	**LLH**	21,636	22,110	19,689	19,873	17,774	17,480	16,657	17,383	17,503	15,972	17,342
(Cost)/Benefit of Error	**HLH**	($610,037)	($531,643)	($478,334)	($432,725)	($272,701)	($270,767)	($259,878)	($343,105)	($397,069)	($450,857)	($165,134)
	LLH	($346,302)	($327,721)	($312,898)	($320,738)	($199,309)	($189,609)	($173,390)	($191,500)	($270,992)	($211,110)	($170,300)
From J.Hirsh												
SalesFcstBDs30Updated(2).xls		**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	
07 Forecast	**HLH**	1,866,922	1,930,316	1,679,588	1,690,815	1,573,197	1,569,710	1,565,199	1,680,791	1,652,106	1,489,185	
07 Forecast	**LLH**	1,315,595	1,312,723	1,167,913	1,165,944	1,042,095	1,093,764	1,067,389	1,114,525	1,084,497	1,008,303	
Load Growth	**HLH**	63,604	58,109	51,278	43,017	50,922	38,304	45,895	54,777	45,318	49,295	
	LLH	29,220	38,131	33,013	36,993	22,835	32,407	26,415	25,555	30,708	22,534	
(Cost)/Benefit of Load Gro	**HLH**	($1,168,700)	($904,726)	($834,604)	($624,871)	($515,712)	($389,928)	($461,435)	($668,539)	($642,269)	($866,718)	
	LLH	($467,690)	($565,195)	($524,638)	($597,050)	($256,064)	($351,521)	($274,969)	($281,523)	($475,439)	($297,842)	
Total Retail Load Forecast	**MWh**	3,182,517	3,243,039	2,847,501	2,856,759	2,615,293	2,663,475	2,632,588	2,795,316	2,736,603	2,497,489	

Table 4.3 Load Variance Documentation

		Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Totals	
Forecast	**HLH**	1,398,924	1,580,524	1,623,935	1,394,767	1,414,558	1,287,434	1,302,361	1,264,623	1,380,772	-	-	63032393	MWh
	LLH	918,118	1,045,375	1,053,546	953,733	955,361	844,959	848,775	830,974	865,558	-	-	40767379	MWh
Forecast Error	**HLH**	29,098	32,875	33,778	29,011	29,423	26,779	27,089	26,304	28,720	-	-	1311074	MWh
2.08%	**LLH**	19,097	21,744	21,914	19,838	19,872	17,575	17,655	17,284	18,004	-	-	847961	MWh
(Cost)/Benefit of Error	**HLH**	($241,311)	($282,280)	($459,186)	($286,045)	($472,532)	($569,196)	($276,547)	($834,265)	($1,204,791)	$ -	$ -	($17,818,676)	Fcst Error
	LLH	($201,373)	($225,239)	($294,068)	($281,773)	($412,619)	($364,861)	($77,627)	($379,461)	($511,860)	$ -	$ -	($10,751,809)	($0.29)
From J.Hirsh														
SalesFcstBDs30Updated(2).xls														
07 Forecast	**HLH**													
07 Forecast	**LLH**													
Load Growth	**HLH**													
	LLH													
														Per unit cost
(Cost)/Benefit of Load Gro	**HLH**												($15,475,076)	Load Growth
	LLH												($8,659,423)	($0.24)
Total Retail Load Forecast	**MWh**												99,230,066	MWh TRL

4.4 GENERATION INPUTS FOR ANCILLARY SERVICES AND OTHER SERVICES

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Table 4.4
Changes Between the WP-07 Final Study and the WP-07 Supplemental Final Study for FY2009 Ancillary and Reserve Product Revenue

Updated 9 July 2008	WP-07 Final Study FY2009 Forecast			WP-07 Supplemental FY2009 Forecast			
	MW	Price	WP-07 Final Study FY2009 Forecast	MW	Price	Forecast	Delta
Redispatch for NT Transmission 1/		$ 1,500,000	$ 1,500,000		$ 1,500,000	$ 1,500,000	$ -
Energy Imbalance 2/		$ -	$ -		$ -	$ -	$ -
Federal RAS for Generation Dropping 3/		$ 396,071	$ 396,071		$ 396,071	$ 396,071	$ -
Generation Supplied Reactive and Voltage Control 4/			$ 12,500,000		$ 4,091,096	$ 4,091,096	$ (8,408,904)
Station Service 5/		$ 2,088,577	$ 2,088,577		$ 2,088,577	$ 2,088,577	$ -
Regulating Reserve 6/	150	$ 7.31	$ 13,161,033	150	$ 7.31	$ 13,158,000	$ -
Operating Reserves - Spinning and Supplemental 7/	380	$ 5.63	$ 25,672,800.00	467	$ 5.63	$ 31,550,520	$ 5,877,720
COE/BOR Network/Delivery Facilities 8/		$ 7,397,000	$ 7,397,000		$ 7,397,000	$ 7,397,000	$ -
Within-Hour Balancing Service for Wind Integration 9/						$ 19,124,320	$ 19,124,320
TOTAL ANCILLARY SERVICES			**$ 62,715,481**			**$ 79,305,584**	$ 16,590,103
Reserve Sales Outside BPAT Control Area 10/			$ 3,630,000			$ 3,630,000	$ -
TOTAL RESERVE SERVICES			**$ 3,630,000**			**$ 3,630,000**	$ -
TOTAL ANCILLARY & RESERVE SERVICES			**$ 66,345,481**			**$ 82,935,584**	**$ 16,590,103**

1/ Revenue forecast is set for FY2009 in the Memorandum of Agreement (MOA) between PS and TS.
2/ No change in the forecast.
3/ Revenue forecast is set for FY2009 in the Memorandum of Agreement between PS and TS.
4/ Updated forecast is compensation to Power Services for Synchronous Condenser Operations. Revenue forecast is set for FY2009 in the Memorandum of Agreement between PS and TS.
5/ Revenue forecast is set for FY2009 in the Memorandum of Agreement between PS and TS.
6/ The forecast of 150 MW was increased to 175 MW in the 2008 Transmission Settlement. As part of the Wind Integration Rate Case settlement, this forecasted amount returns to 150 MW.
7/ Updated forecast based on Transmission Service notification to Power Services per the MOA that PBL Requirement Operating Reserve need for FY2008 would be 467 MW.
8/ Revenue forecast is set for FY2009 in the Memorandum of Agreement between PS and TS.
9/ Forecasted amount of revenue to be a credit toward power rates per the Wind Integration Rate Case Settlement signed March 2008.
10/ No change in the forecast.

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4.4.1 Operating Reserves

Section 4.4.1 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Operating Reserves
(x1000)

		Average Over Rate Period	
	Operating Reserves Generation Input	**Subtotals (X000)**	**Totals (X000)**
1	**All Hydro Projects**		
2	O&M	$ 216,244	
3	Depreciation	$ 86,396	
4	Net Interest	$ 112,745	
5	Planned Net Revenues	$ 34,013	
6	Total Revenue Requirement		$ 449,398
7	**Fish & Wildlife**		
8	O&M **1/**	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,365
13	**A&G Expense 1/**		$ 92,349
14	**Total Revenue Requirement**		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost 2/	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	**Net Revenue Requirement**		**$ 771,201**

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council
2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

Section 4.4.1 - Table 1B
Summary of Assumptions and Application of Methods to Develop Per Unit Generation Input and Annual Revenue Forecast for Operating Reserves
(Average over Rate Period)

	Operating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
	Forecast of Average Hydro Generation System Uses	**Average MWs**
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
9	**Total Average Hydro Generation System Uses**	**9,947**
	Factor to Apply to Revenue Requirement	**Average MWs**
10	Total PBL Reserve Obligation (Line 4)	380
11	Total Average Control Area Generation (Line 9)	9,947
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03820**
	Adjusted Revenue Requirement	**Average $'s**
13	Power Revenue Requirement for ALL Hydro Projects	**$771,201,466**
14	Multiplication Factor (Line 12)	3.8202%
15	**Adjusted Revenue Requirement for Operating Reserves**	**$ 29,461,803**
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Operating Reserves (Line 15)	$ 29,461,803
17	Total PBL Reserve Obligation (Line 4) * 12 *1000	4,560,000
18	**Per Unit Rate Express Kw-Mo (Line 16 / Line 17)**	**$ 6.46**
	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total PBL Reserve Obligation (Line 4)	380
20	Per Unit Generation Input Rate	$ 6.46
21	**Annual Revenue Forecast (Line 19 * Line 20 *12*1000)**	**$ 29,461,803**

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4.4.2 Regulating Reserves

Section 4.4.2 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Regulating Reserves
(x1000)

		Average Over Rate Period	
	Regulating Reserves Generation Input	**Subtotals (X000)**	**Totals (X000)**
1	**Big 10 Dams**		
2	O&M	$ 166,675	
3	Depreciation	$ 66,928	
4	Net Interest	$ 88,949	
5	Planned Net Revenues	$ 26,225	
6	Total Revenue Requirement		$ 348,777
7	**Fish & Wildlife**		
8	O&M **1/**	$ 208,872	
9	Amortization/Depreciation	$ 36,042	
10	Net Interest	$ 35,053	
11	Planned Net Revenues	$ 10,397	
12	Subtotal Fish & Wildlife		$ 290,364
13	**A&G Expense 1/**		$ 92,349
14	**Total Revenue Requirement**		
15	Revenue Credits		
16	4h10C (non-operations)	$ 39,917	
17	Colville payment Treas. Credit	$ 4,600	
18	Generation Supplied Reactive Generation Input Cost **2/**	$16,394	
19	Subtotal Revenue Credits		$ 60,911
20	**Net Revenue Requirement**		**$ 670,579**

1/ Power Marketing, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

2/ Average forecasted revenue for Generation Supplied Reactive over three-year rate period

Section 4.4.2 - Table 1B

Summary of Assumptions and Application of Methods to Develop Per Unit Generation Input and Annual Revenue Forecast for Regulating Reserves (Average over Rate Period)

		FY07-09
	Regulating Reserve Assumptions	**Average MWs**
1	**Regulated + Independent Hydro**	**9,217**
2	Total BPA Control Area Reserve Obligation (Line 3 + 4)	690
3	Total Self-Supply and Third Party-Supply Reserve Obligation	310
4	**Total PBL Reserve Obligation**	**380**
5	**Control Area Regulation Requirement.**	**350**
5b	**TBL Regulating Reserves Requirement**	**150**
	Forecast of Average Hydro Generation System Uses	**Average MWs**
6	Average Hydro Generation (Line 1)	9,217
7	Total PBL Reserve Obligation (Line 4)	380
8	Control Area Regulation Requirement (Line 5)	350
9	**89% Average Hydro Generation System Uses**	**8,933**
		.
	Factor to Apply to Revenue Requirement	**Average MWs**
10	Control Area Regulating Requirement (Line 5)	350
11	Total Average Control Area Generation (Line 9)	8,933
12	**Multiplication Factor for Revenue Requirement (Line 10 / Line 11)**	**0.03918**
	Adjusted Revenue Requirement	**Average $'s**
13	Power Revenue Requirement for Big 10 Hydro Projects	**$670,579,044**
14	Multiplication Factor (Line 12)	3.9180%
15	**Adjusted Revenue Requirement for Regulating Reserves**	**$ 26,273,284**
	Per Unit Rate	**Average $'s**
16	Adjusted Revenue Requirement for Regulating Reserves (Line 15)	$ 26,273,284
17	Total Regulating Reserve Obligation (Line 4) * 12 *1000	4,560,000
18	**Per Unit Rate in Kw-Mo (Line 16 / Line 17)**	$ 5.76
	Annual Revenue Forecast for Operating Reserves	**Average $'s**
19	Total TBL Regulating Reserve Obligation (Line 5b)	150
20	Per Unit Rate in Kw-Mo (Line 16 / Line 17)	$ 5.76
20a	AGC Adder	$ 1.55
20b	Total Per Unit Rate (Linw 20 + 20a)	**$ 7.31**
21	**Annual Revenue Forecast (Line 19 * Line 20b *12*1000)**	**$ 13,161,033**

Section 4.4.2 - Table 2
AGC Adder Assumptions

	Big 10 Capacity		Turbine Type	Peak Efficiency MWs
1	GCC	Grand Coulee	Francis	5,467
2	CHJ	Chief Joseph	Francis	2,168
3	JDA	John Day	Kaplan	1,984
4	TDA	The Dalles	Kaplan	1,665
5	BON	Bonneville	Kaplan	841
6	MCN	McNary	Kaplan	706
7	LGS	Little Goose	Kaplan	730
8	LMN	Lower Monumental	Kaplan	706
9	LWG	Lower Granite	Kaplan	730
10	IH	Ice Harbor	Kaplan	658
11	**Francis Total Capacity**			**7,635**
12	**Kaplan Total Capacity**			**8,020**

Section 4.4.2 - Table 3
AGC Adder Calculation
BPA Incremental Cost of Regulation (AGC)

	Efficiency-Lost Costs of Regulation 1/	Kaplan	Francis	Notes
1	Efficiency Loss	25%	29%	On all kWh on AGC
2	kWh with Efficiency Loss	8,760	8,760	kWh per kW-yr on AGC
3	kWh Lost	22	25	per kW-yr on AGC
4	Average Price	30	30	$/MWh
5	Revenue Loss	0.66	0.77	per kW-yr on AGC
	Incremental Increased O&M Costs of Regualtion 1/	**Kaplan**	**Francis**	
6	Base O&M Cost per kW of Francis & Kaplan Capacity	13.78	8.78	$/kW-yr
7	Percent O&M Increase due to AGC (inc. small capital)	15%	10%	
8	Incremental O&M Costs for Regulation	2.07	0.88	per kW-yr on AGC
	AGC Multiplier 2/	**Kaplan**	**Francis**	
9	AGC Multiplier	3.70	12.30	kW on AGC per kW of AGC Resp
	Total Cost of Regulation	**Kaplan**	**Francis**	
10	Efficiency Loss Cost	0.66	0.77	kW on AGC per kW of AGC Resp
11	Increased O&M Cost	2.07	0.88	
12	Subtotal	2.73	1.65	
13	Multiply Costs by AGC Multiplier	3.70	12.30	
14	Costs per kW-yr of AGC Effciency Lost Cost	$2.44	$9.47	
15	Increased O&M Cost	$7.66	$10.82	
16	Total AGC Incremental Cost	$10.10	$20.30	
17	MW * Hours of AGC	3,485,639	16,708,059	per kW-yr of AGC Capability
18	Weight	17%	83%	
19	Weighted Average	18.56		per kW-yr of AGC Capability
20	**Weighted Average**	**1.55**		**per kW-mo** of AGC Capability

1/ Applied to all MW on AGC, not just MW of AGC Capability
2/ Calculate MW on AGC required to yield 1 MW of AGC Response Capability

Section 4.4.2 - Table 4
AGC Adder & Multiplier Worksheet

Summary of Equipment (Francis Units)
Grand Coulee
6 Operated @ 73 MW
? Eff = 0.3%
Range = 14 MW
Multiplier = 73 MW/14 MW * 2 = 10.4
12 Operated @ 81 MW
? Eff = 0.3%
Range = 20 MW
Multiplier = 81 MW/20 MW * 2 = 8.1
3 Operated @ 600 MW
? Eff = 0.2%
Range = 95 MW
Multiplier = 600 MW/95 MW * 2 = 12.6
3 Operated @ 718 MW
? Eff = 0.25%
Range = 167 MW
Multiplier = 718 MW/167 MW * 2 = 8.6

Calculation for Francis Units Weighted Multiplier
6 (73) 10.4 + 12 (81) 8
+3 (600) 12.6 + 3 (718) 8.6
+11 (88) 19.6 + 6 (75) 8.8
+10 (75) 21.4/WGTS = 92,518/7,532
12.3 Francis
6 (73) (3) + 12 (81) (3)
+3 (600) 2 + 3 (718) 2.5
+11 (88) 3.3 + 6 (75) 3.3
+10 (75) 5/WGTS = 21,644/7,532
.29% Francis

Chief Joseph
11 Operated @ 88 MW
? Eff = 0.33%
Range = 9 MW
Multiplier = 88 MW9 MW * 2 = 19.6
6 Operated @75 MW
? Eff = 0.33%
Range = 17 MW
Multiplier = 75 MW/17 MW * 2 = 8.8
10 Operated @ 75 MW
? Eff = 0.5%
Range = 7 MW
Multiplier =75 MW/7 MW * 2 = 21.4

Calculation for Kaplan Units Weighted Multiplier
.25% Kaplan
Range = 23.7 MW
Operated @ 43.7 MW
Multiplier = 43.7/23.7*2 = 3.68 Kaplan

4.4.3 REACTIVE SUPPLY AND VOLTAGE CONTROL

Section 4.4.3 - Table 1
Summary of Costs Assigned to TBL for the Generation Input for Generation Supplied Reactive Power and Voltage Control
(x1000)

		FY07	
	Costs for Electric Plant	**Total for Electric Plant**	**Allocated to Reactive**
1	Federal Hydro Generating Projects		
2	O&M	$ 80,329	
3	A&G Expenses	$ 14,395	
4	Depreciation	$ 27,342	
5	Net Interest Expense	$ 35,052	
6	Minimum Required Net Revenues	$ 13,211	
7	Generation Integration (BPA Facilities)	$ 9,297	
8	Revenue Requirement for Electrical Equipment (Total)	$ 179,626	
9	Reactive Allocation of Electrical RR (10%)	179626 x 10%	$ 17,963
10	Non-Federal Projects (CGS)	$ 3,399	
11	Reactive Allocation of Electrical RR (5%)	3,399 x 5%	$ 170
12	**Other Costs (Assigned 100% to Reactive)**		
13	Synchronous Condenser Real Power Consumption		$ 3,726
14	Synchronous Condenser Modifications (Paid by PBL)		$ 365
15	Real Power losses due to reactive production		$ 1,958
16	**Total Average Annual Cost**		**$ 24,182**

4.4.3 Reactive Supply and Voltage Control Table 2

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 3
Corps of Engineers Facilities Included in Reactive Allocation

Category	From COE Account	Items Included
Generator	7200 Turbine/Generator	Generator, stator, air coolers, rotor, compressor for condensing.
Exciter	7200 Turbine/Generator	Generator exciter.
Voltage Regulator	7300 Power Plant	Voltage regulation and excitation equipment.
Electrical Equipment	7300 Power Plant	Miscellaneous equipment, generator grounding, main bus or cable, generator switchgear, control cable, load control equipment.
Switchyard	7600 Switchyard	All switchyard equipment.
Accessory Equipment	7300 Power Plant	Station service main bus, annuniciator system, grounding system, station service, antenna towers, radio buildings, engine generator sets, control switchboards, battery switchboards, recording annunciators, data logging equipment, SCADA equipment, central
	7400 Miscellaneous Powerplant Equipment	Bridge/gentry cranes, lubrication, fire protection, air system, radio/MW buildings and equipment, oil purifiers, air compressors, plant communication equipment (Excluded are tailrace cranes and drainage equipment)

Section 4.4.3 - Table 4
USBR Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

USBR Plants	[1] Gross Plant 1/	[2] Gross Power Plant-Hydro (includes Waterwheels, Turbines and Generators2/	[3] % Electrical to allocate to Electric Plant (used to separate Turbine costs from Powerlants- Hydro)3/	[4] Subtotal Gross Electrical	[5] % Gross Electrical Divided by Gross Plant	[6] Gross Generation Integration	[7] Gross GI (% of Transmission) 4/	[8] Gross Generation Integration allocated to Electric Plant	[9] Total Net Electrical Allocated to Reactive Power	Gross Plant assigned to Electrical (%of Gross Plant)
				[2] X [3]	[4] / [1]			[6] X [7]	[4] + [8]	[9] / [1]
Boise	$ 26,326,436	$ 25,438,829	50%	$ 12,719,415	48%	$ 953,782	100.0%	$ 953,782	$ 13,673,197	**51.9%**
Columbia Basin Grand Coulee	$ 1,029,337,473	$ 757,610,923	50%	$ 378,805,462	37%	$ 178,831,533	76.2%	$ 136,269,628	$ 515,075,090	**50.0%**
Hungry Horse	$ 134,408,930	$ 49,452,271	50%	$ 24,726,135	18%	$ 11,854,647	79.1%	$ 9,377,026	$ 34,103,161	**25.4%**
Minidoka/ Palisades	$ 121,835,132	$ 117,889,095	50%	$ 58,944,548	48%	$ 3,703,353	58.7%	$ 2,173,868	$ 61,118,416	**50.2%**
Yakima **5/**	$ 5,810,089	$ 5,098,190	50%	$ 3,492,110	60%	$ -	100.0%	$ -	$ 3,492,110	**60.1%**
Green Springs Project **5/**	$ 10,778,940	$ 3,598,237	50%	$ 1,799,119	17%	$ 176,398	100.0%	$ 176,398	$ 1,975,516	**18.3%**

1/ Data taken from Plant , Property and Equipment Accounts as of September 30, 2004, Includes Interest During Construction (IDC)

2/ Includes Generator/Exciter/Voltage Regulator/Accessory Electrical. USBR does not separate turbine investments from generator investment (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)

3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.

4/ Percent (%) determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with more detailed cost data in Generation Integration (GI) Study.

5/ Portions of Electirc Plant and all Transmission allocated to Irrigation - Plant, Property and Equipment Accounting, September 30, 2004. Excludes Lower Snake and Columbia River bypass, which are fish related investments.

Section 4.4.3 - Table 5A
COE Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

COE Plants 1/	Gross Plant	Powerhouse (7000/7100) [1]	Turbines and Generators 2/ (7200) [2]	Powerplant Accessory Equipment (7300) [3]	Misc Powerplant equip (7400) [4]	% to exclude turbine costs and allocate accessory electrical equipment (estimated based on historical and investment cost data) 3/ [5]	Turbines and Generators allocated to Reactive Power [6]	50% Powerhouse [7]
							[5] X [2]	
Albeni Falls	$ 43,125,908	$ 13,962,040	$ 8,739,715	$ 2,105,926	$ 569,628	50%	$ 4,369,858	$ 6,981,020
Bonneville	927,603,078	362,500,774	195,747,924	14,741,265	10,939,614	50%	97,873,962	181,250,387
Ch Jo	571,149,469	85,543,955	163,583,240	36,981,589	4,081,539	50%	81,791,620	42,771,978
Cougar	36,313,701	1,974,458	3,597,784	454,443	813,857	50%	1,798,892	987,229
Detroit	41,220,358	5,140,402	6,772,374	3,020,914	641,842	50%	3,386,187	2,570,201
Dworshak	316,781,862	15,799,443	13,251,369	8,569,384	3,529,274	50%	6,625,685	7,899,722
GrnPet/Foster	50,954,947	3,897,571	5,871,676	1,418,328	508,702	50%	2,935,838	1,948,786
HillsCr	18,463,456	1,119,110	3,470,135	810,841	309,015	50%	1,735,068	559,555
Ice Harbor	159,246,545	51,318,297	38,642,504	9,700,253	2,687,275	50%	19,321,252	25,659,149
John Day	494,244,110	111,669,313	112,346,998	18,169,669	4,587,172	50%	56,173,499	55,834,657
Libby	433,211,642	37,415,453	62,141,172	8,619,908	3,684,712	50%	31,070,586	18,707,727
Little Goose	212,067,726	58,672,560	50,077,438	11,882,402	1,747,744	50%	25,038,719	29,336,280
LookOut	50,191,766	5,204,083	10,832,943	7,963,445	832,164	50%	5,416,472	2,602,042
LostCr	26,971,889	3,860,301	5,431,228	786,500	1,387,004	50%	2,715,614	1,930,151
Lower Granite	332,598,745	68,956,661	50,825,691	11,391,791	3,045,193	50%	25,412,846	34,478,331
Lower Monumental	230,564,378	58,186,024	51,143,566	11,422,584	1,641,242	50%	25,571,783	29,093,012
McNary	300,735,946	75,025,036	65,509,917	21,433,623	3,374,034	50%	32,754,959	37,512,518
The Dalles	308,486,648	92,794,123	130,964,391	19,930,866	8,588,004	50%	65,482,196	46,397,062

1/ Accounting Data from Plant, Property and Equipment Accounts as of October 2004
2/ COE does not separate turbine investments from generator investment (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)
3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.
4/ 50% of the Power Plant, Power Plant Accessory Electrical and Misc Power Plant Equipment is assigned to the Electric Plant.
5/ %'s determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with more detailed cost data in Generation Integration Study.

Section 4.4.3 - Table 5B
COE Gross Investment Data to Determine Percentage of Gross Plant to Allocate to Reactive Power Production

COE Plants 1/	50 % Powerplant Accessory Equipment Allocated to Reactive [8]	50% Misc Powerplant Equipment Allocated to Reactive [9]	Subtotal Net Electrical Allocated to Reactive Power [10]	Gross Generation Integration (7600) 5/ [11]	Gross Generation Integration (% of Transmission) [12]	Gross Generation Integration allocated to Electric Plant [13]	Total Net Electrical Allocated to Reactive Power [14]	% Gross Plant allocated to Electrical Plant [15]
			[6]+[7]+[8]+[9]				[10]+[13]	[14]/Gross Plant
Albeni Falls	$ 1,052,963	$ 284,814	$ 12,688,655	$ 695,252	100%	$ 695,252	$ 13,383,907	**31%**
Bonneville	7,370,633	5,469,807	291,964,789	39,009,024	88%	34,249,923	326,214,712	**35%**
Ch Jo	18,490,795	2,040,770	145,095,162	19,770,689	100%	19,770,689	164,865,851	**29%**
Cougar	227,222	406,929	3,420,271	143,103	100%	143,103	3,563,374	**10%**
Detroit	1,510,457	320,921	7,787,766	1,141,762	100%	1,141,762	8,929,528	**22%**
Dworshak	4,284,692	1,764,637	20,574,735	1,765,530	100%	1,765,530	22,340,265	**7%**
GrnPet/Foster	709,164	254,351	5,848,139	1,351,853	100%	1,351,853	7,199,992	**14%**
HillsCr	405,421	154,508	2,854,551	133,724	100%	133,724	2,988,275	**16%**
Ice Harbor	4,850,127	1,343,638	51,174,165	1,531,193	100%	1,531,193	52,705,358	**33%**
John Day	9,084,835	2,293,586	123,386,576	5,485,427	100%	5,485,427	128,872,003	**26%**
Libby	4,309,954	1,842,356	55,930,623	4,176,296	100%	4,176,296	60,106,919	**14%**
Little Goose	5,941,201	873,872	61,190,072	3,341,903	100%	3,341,903	64,531,975	**30%**
LookOut	3,981,723	416,082	12,416,318	619,036	100%	619,036	13,035,354	**26%**
LostCr	393,250	693,502	5,732,517	462,080	100%	462,080	6,194,597	**23%**
Lower Granite	5,695,896	1,522,597	67,109,668	4,770,350	100%	4,770,350	71,880,018	**22%**
Lower Monumental	5,711,292	820,621	61,196,708	2,796,164	100%	2,796,164	63,992,872	**28%**
McNary	10,716,812	1,687,017	82,671,305	4,997,519	100%	4,997,519	87,668,824	**29%**
The Dalles	9,965,433	4,294,002	126,138,692	1,952,308	100%	4,667,203	130,805,895	**42%**

1/ Accounting Data from Plant, Property and Equipment Accounts as of October 2004
2/ COE does not separate turbine investment from generator investment. (turbine costs estimated based on historical cost data from FY2002-FY2006 rate period where available)
3/ For plants with no historical information to separate turbine and generator investment, half of the turbine/generator investment is assumed to be generator equipment.
4/ 50% of the Power Plant, Power Plant Accessory Electrical and Misc Power Plant Equipment is assigned to the Electric Plant.
5/ Percent **(**%) determined using Transmission Segmentation Study in 1996 rate case. Grand Coulee Netwok and delivery costs updated with ore detailed cost data in Generation Integration Study.

Section 4.4.3 - Table 6
Percentage to apply COE and BOR Capital Replacements

	[A]	[B]	[C]	[D]	[E]	[F]	
	Planned Replacements (Total)	Electrical	Accessory Electrical	Mechanical	Transmission	GI portion of transmisison	Electrical Replacements (Percentage) 1/
							([B]+ 50%[C]) +([D])/[A])
2005	$ 121,169	$ 42,948	$ 8,500	$ 39,250	$ 30,470	$ 20,583	55.9%
2006	$ 112,685	$ 61,159	$ 12,142	$ 30,087	$ 9,297	$ 8,301	67.0%
2007	$ 58,818	$ 40,788	$ 7,310	$ 9,970	$ 750	$ 375	76.2%
2008	$ 32,516	$ 19,202	$ 11,425	$ 1,889	$ -	$ -	76.6%
2009	$ 163,269	$ 18,941	$ -	$ 127,452	$ 16,876	$ 8,438	16.8%
Average percentage to allocate capital additions/ replacements to electric plant:							**58.5%**

Notes:
1/ Based on **PROJECTED** electrical vs mechanical capital program
Allocate 50% Accessory equipment to electrical

4.4.3 Reactive Supply and Voltage Control Table 7

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 8
Columbia Generating Station

DESCRIPTION	ACQUISITION COST	ACCUM DEPR 12/31/1997	NET PLANT 12/31/1997	LIFE/YEARS
Nuclear Production - Turbogenerator *				
Excitation & Voltage	$ 1,292,835	$ 420,720	$ 872,116	40
Main generator	18,966,373	6,150,485	12,815,889	40
Hydrogen - Generator cooling	1,865,010	696,136	1,168,874	35
Hydrogen - Generator seal oil	806,016	300,824	505,192	35
Storage & Supply - Generator Hydrogen	400,529	138,471	262,058	35
Stator - Generator Cooling	618,090	230,705	387,385	35
Isolated Phase - Bus Duct Cooling	89,150	46,604	42,546	25
Subtotal	**$ 24,038,003**	**$ 7,983,944**	**$ 16,054,058**	
Transmission - Station Equipment				
Transformers	$ 4,750,999	$ 2,057,206	$ 2,693,793	30
Circuit Breakers	124,182	64,553	59,629	25
Tie-ins	47,911	24,905	23,006	25
Subtotal	**$ 4,923,092**	**$ 2,146,664**	**$ 2,776,428**	
Total Electrical & Transmission	**$ 28,961,095**	**$ 10,130,608**	**$ 18,830,486**	
Total Net Plant (from "Combining Balance Sheets - Assets")			**$ 2,531,782,112**	
Transmission as percent of total net plant investment			0.11%	
Electrical as percent of total net plant investment			0.63%	
Electrical and Transmission as percent of total net plant investment			0.74%	

Determined in FY2002-FY2006 rate period
*** Excludes turbine and steam components**
Service Date: 12/84
Depreciation Method: Straight Line

Section 4.4.3 - Table 9
Reactive - Electric Portion of
Power Revenue Requirement for Federal Base System Generating Units

	($ in thousands)	2007	2008	2009	Average Over Rate Period
1	O&M	$ 80,335	$ 83,602	$ 87,078	$ 83,672
2	A&G Expense [1/]	14,807	15,216	15,640	15,221
3	Depreciation	26,490	26,185	26,556	26,410
4	Non-Federal Projects (CGS)	3,780	3,287	3,684	3,584
5	Net Interest Expense	39,272	39,159	40,269	39,567
6	Minimum Required Net Revenues	7,461	8,908	5,648	7,339
7	**Total Revenue Requirement**	**$ 172,145**	**$ 176,357**	**$ 178,875**	**$ 175,792**

1/Power Scheduling and Generation Project Coordination

	Calculations:	2007	2008	2009	Average Over Rate Period
1	Total Electric Average Net Plant	$ 1,249,664	$ 1,200,345	$ 1,201,922	$ 1,217,310
2	Total Corps/Bureau Average Net Plant	$ 4,775,952	$ 4,831,698	$ 4,902,276	$ 4,836,642
3	**percent electric**	26.17%	24.84%	24.52%	$ 0
4	Corps/Bureau Net Interest	$ 150,089	$ 157,625	$ 164,244	$ 157,319
5	**Electric Net Interest**	$ 39,272	$ 39,159	$ 40,269	$ 39,567
6	Corps/Bureau MRNR	$ 28,513	$ 35,858	$ 23,037	$ 29,136
7	**Electric MRNR**	$ 7,461	$ 8,908	$ 5,648	$ 7,339
8	Total COE O&M 1/	$ 123,759	$ 128,781	$ 134,344	$ 128,961
9	**COE Electric O&M @ 42%**	$ 51,979	$ 54,088	$ 56,424	$ 54,164
10	Total BOR O&M 2/	$ 63,014	$ 65,586	$ 68,120	$ 65,573
11	**BOR Electric O&M @ 45%**	$ 28,356	$ 29,514	$ 30,654	$ 29,508
12	CGS costs 3/	$ 510,755	$ 444,158	$ 497,872	$ 484,262
13	**CGS Electric @ 0.74%**	$ 3,780	$ 3,287	$ 3,684	$ 3,584

1/excludes Lower Snake F&W and O&M attributable in the aggregate to F&W at projects.

2/excludes payment to Colville Tribes, shown elsewhere in Columbia Basin O&M and F&W.

3/debt service and O&M (excludes nuclear insurance, fuel and revenue-financed capital).

	Determination of Synchronous Condensor Annual Costs:	2007	2008	2009	Average Over Rate Period
14	Synchronous Condensers Avg Net Plt	$ 6,885	$ 6,782	$ 6,679	$ 6,782
15	Total Corps/Bureau Average Net Plant	$ 4,775,952	$ 4,831,698	$ 4,902,276	$ 4,836,642
16	Percent	0.14%	0.14%	0.14%	$ 0
17	Corps/Bureau Net Interest	$ 150,089	$ 157,625	$ 164,244	$ 157,319
18	**Sync Cond Net Interest**	$ 216	$ 221	$ 224	$ 220
19	Corps/Bureau MRNR	$ 28,513	$ 35,858	$ 23,037	$ 29,136
20	Sync Cond MRNR	$ 41	$ 50	$ 31	$ 41
21	**Sync Cond Depreciation**	$ 103	$ 103	$ 103	$ 103
22	**Total Sync Cond Costs**	$ 360	$ 374	$ 358	$ 364

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/05**			**9/30/06**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
Bureau of Reclamation						
BOISE	29,179	8,710	389			
historic reactive	15,144	4,520	202	15,144	4,722	202
projected				410	3	3
COLUMBIA BASIN	1,224,791	384,977	16,331			
historic reactive	612,396	192,489	8,166	612,396	200,655	8,166
projected				1,442	10	10
GREEN SPRINGS	11,162	8,521	149			
historic reactive	2,043	1,559	27	2,043	1,586	27
projected				-	-	-
HUNGRY HORSE	119,591	48,598	1,595			
historic reactive	30,376	12,344	405	30,376	12,749	405
projected				4,102	27	27
MINIDOKA-PALISADES	110,217	23,959	1,470			
historic reactive	55,329	12,027	738	55,329	12,765	738
projected				-	-	-
YAKIMA	6,115	3,132	82			
historic reactive	3,675	1,882	49	3,675	1,931	49
projected	-			614	4	4
Total Bureau	2,190,839	694,008	29,214	725,531	234,452	9,631

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/05**			**9/30/06**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
ALBENI FALLS	43,239	21,721	577			
historic	13,404	6,734	179	13,404	6,913	179
projected				1,952	13	13
BONNEVILLE	961,873	316,631	12,825			
historic	336,656	110,821	4,489	336,656	115,310	4,489
projected				4,001	27	27
CHIEF JOSEPH	574,919	230,980	7,666			
historic	172,476	69,294	2,300	172,476	71,594	2,300
projected				4,110	27	27
COUGAR	72,804	8,590	971			
historic	3,640	430	49	3,640	479	49
projected				5,342	36	36
DETROIT-BIG CLIFF	43,810	24,151	584			
historic	9,638	5,313	128	9,638	5,441	128
projected				5,779	39	39
DWORSHAK	292,417	98,974	3,899			
historic	20,469	6,928	273	20,469	7,201	273
projected				2,143	14	14
GREEN PETER-FOSTER	55,614	20,955	742			
historic	7,786	2,934	104	7,786	3,038	104
projected				-	-	-
HILLS CREEK	19,683	10,099	262			
historic	2,952	1,515	39	2,952	1,554	39
projected				310	2	2
ICE HARBOR	165,052	70,313	2,201			
historic	54,467	23,203	726	54,467	23,929	726
projected				1,369	9	9
JOHN DAY	506,555	187,352	6,754			
historic	131,704	48,712	1,756	131,704	50,468	1,756
projected				5,169	34	34
LIBBY	433,679	132,919	5,782			
historic	69,389	21,267	925	69,389	22,192	925
projected				4,183	28	28
LITTLE GOOSE	212,666	92,511	2,836			
historic	63,800	27,753	851	63,800	28,604	851
projected				1,358	9	9

Section 4.4.3 - Table 10A

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/05**			**9/30/06**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
LOOKOUT POINT	59,931	38,487	799			
historic	14,383	9,237	192	14,383	9,429	192
projected				-	-	-
LOST CREEK	27,138	9,947	362			
historic	5,428	1,989	72	5,428	2,061	72
projected				884	6	6
LOWER GRANITE	336,476	120,939	4,486			
historic	74,025	26,607	987	74,025	27,594	987
projected				3,406	23	23
LOWER MONUMENTAL	232,606	99,110	3,101			
historic	65,130	27,751	868	65,130	28,619	868
projected				3,763	25	25
MCNARY	312,291	176,552	4,164			
historic	90,564	51,200	1,208	90,564	52,408	1,208
projected				1,325	9	9
THE DALLES	357,152	175,010	4,762			
historic	150,004	73,504	2,000	150,004	75,504	2,000
projected	980	7	7	13,071	101	94
Total Corps	5,951,561	2,328,719	79,349	1,344,080	532,740	17,541
Total Corps and Bureau	8,142,400	3,022,727	108,563	2,069,611	767,192	27,172

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
Bureau of Reclamation									
BOISE									
historic reactive	15,144	4,924	202	15,144	5,126	202	15,144	5,328	202
projected	-	6	3	-	6	-	-	6	-
COLUMBIA BASIN									
historic reactive	612,396	208,821	8,166	612,396	216,987	8,166	612,396	225,153	8,166
projected	2,944	39	29	5,682	97	58	73,246	623	526
GREEN SPRINGS									
historic reactive	2,043	1,613	27	2,043	1,640	27	2,043	1,667	27
projected	-	-	-	-	-	-	-	-	-
HUNGRY HORSE									
historic reactive	30,376	13,154	405	30,376	13,559	405	30,376	13,964	405
projected	240	56	29	1,002	64	8	-	71	7
MINIDOKA-PALISADES									
historic reactive	55,329	13,503	738	55,329	14,241	738	55,329	14,979	738
projected	483	3	3	-	6	3	-	6	-
YAKIMA									
historic reactive	3,675	1,980	49	3,675	2,029	49	3,675	2,078	49
projected	1,354	17	13	-	26	9	-	26	-
Total Bureau	723,983	244,116	9,664	725,647	253,781	9,665	792,209	263,901	10,120

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
ALBENI FALLS									
historic	13,404	7,092	179	13,404	7,271	179	13,404	7,450	179
projected	-	26	13	-	26	-	-	26	-
BONNEVILLE									
historic	336,656	119,799	4,489	336,656	124,288	4,489	336,656	128,777	4,489
projected	2,615	71	44	3,967	115	44	-	141	26
CHIEF JOSEPH									
historic	172,476	73,894	2,300	172,476	76,194	2,300	172,476	78,494	2,300
projected	2,102	68	41	-	82	14	-	82	-
COUGAR									
historic	3,640	528	49	3,640	577	49	3,640	626	49
projected	249	73	37	-	75	2	-	75	-
DETROIT-BIG CLIFF									
historic	9,638	5,569	128	9,638	5,697	128	9,638	5,825	128
projected	2,483	94	55	-	111	17	-	111	-
DWORSHAK									
historic	20,469	7,474	273	20,469	7,747	273	20,469	8,020	273
projected	348	31	17	1,485	43	12	858	59	16
GREEN PETER-FOSTER									
historic	7,786	3,142	104	7,786	3,246	104	7,786	3,350	104
projected	858	6	6	-	12	6	-	12	-
HILLS CREEK									
historic	2,952	1,593	39	2,952	1,632	39	2,952	1,671	39
projected	248	6	4	-	8	2	187	9	1
ICE HARBOR									
historic	54,467	24,655	726	54,467	25,381	726	54,467	26,107	726
projected	-	18	9	-	18	-	1,525	28	10
JOHN DAY									
historic	131,704	52,224	1,756	131,704	53,980	1,756	131,704	55,736	1,756
projected	4,938	101	67	-	134	33	-	134	-
LIBBY									
historic	69,389	23,117	925	69,389	24,042	925	69,389	24,967	925
projected	-	56	28	-	56	-	-	56	-
LITTLE GOOSE									
historic	63,800	29,455	851	63,800	30,306	851	63,800	31,157	851
projected	-	18	9	1,987	31	13	496	48	17

Section 4.4.3 - Table 10B

Investment, Accumulated Depreciation, Depreciation Expense by Project Assigned to Reactive ($ in thousands)

Service Lives = 75 yrs	**9/30/07**			**9/30/08**			**9/30/09**		
	gross	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**	**gross**	**acc dep**	**depr exp**
LOOKOUT POINT									
historic	14,383	9,621	192	14,383	9,813	192	14,383	10,005	192
projected	1,952	13	13	114	27	14	260	29	2
LOST CREEK									
historic	5,428	2,133	72	5,428	2,205	72	5,428	2,277	72
projected	-	12	6	-	12	-	380	15	3
LOWER GRANITE									
historic	74,025	28,581	987	74,025	29,568	987	74,025	30,555	987
projected	6,601	90	67	2,889	153	63	-	172	19
LOWER MONUMENTAL									
historic	65,130	29,487	868	65,130	30,355	868	65,130	31,223	868
projected	-	50	25	1,895	63	13	495	79	16
MCNARY									
historic	90,564	53,616	1,208	90,564	54,824	1,208	90,564	56,032	1,208
projected	-	18	9	-	18	-	3,749	43	25
THE DALLES									
historic	150,004	77,504	2,000	150,004	79,504	2,000	150,004	81,504	2,000
projected	2,331	204	103	-	220	16	4,444	250	30
Total Corps	1,310,640	550,439	17,699	1,298,252	567,834	17,395	1,298,309	585,145	17,311
Total Corps and Bureau	2,034,623	794,555	27,363	2,023,899	821,615	27,060	2,090,518	849,046	27,431

4.4.3 Reactive Supply and Voltage Control Table 11

Table Deleted. The data either no longer exists, is no longer applicable, or has been merged with other data.

Section 4.4.3 - Table 12
Generation Supplied Reactive Power and Voltage Control
Synchronous Condenser Energy Costs
Value of Energy Consumed for
Synchronous Condenser (Motoring) Operation

Generating Project	Nameplate rating (MW/unit)	Motoring power consumption (MW/unit)	Number of Units used	Hourly Energy Consumption (MW)	Motoring hours/year	Total Cost of Energy
John Day units (4units) 1/	155	2	4	8.0	925	$202,242
The Dalles units 14-20 1/	99	1.2	6	7.2	925	$182,018
Libby units 1-5 3/	0	0.0	0	0.0	0	$0
Palisades units 1-4	44	0.6	1	0.6	100	$1,563
Hungry Horse units 1-4 3/	107	0.0	0	0.0	0	$0
Grand Coulee units 19-24 2/	825	10.0	3	30.0	4,074	$3,340,273
TOTAL ENERGY COST						**$3,726,096**
Value of energy (mills/kW-hr)	**27.33**					

1/ The hours shown for The Dalles are estimated to be the same as John Day. There is no historical basis for The Dalles since the condensing units at The Dalles were just reconfigured to have the same functionality as John Day.
2/ At Coulee, six units (19-24) are connected to the 500kV bus, and are kept spinning for both TBL and USBR operations. For this study, half the condensing hours are considered "used," by TBL for voltage control and the other half "used" by USBR operations.
3/ These projects have not been in condensing mode for the last couple of years.

Section 4.4.3 - Table 13
Generator Losses -
Allocated to Generation Input for Reactive Power and Voltage Control

A.	Generating Capacity (MW)		**21,353**
B.	Stator Load Loss Differential (MW) **1/**		8
C.	Rotor (Field) Load Loss Differential **1/**		12
D.	Exciter Load Loss Differential **1/**		1
E.	Total Load Loss Due to Reactive Loading		**20**
	No-Load Loss Component		
1.	No-Load Loss		
2.	Generator Allocation Factor (10%)		11
3.	No-Load Reactive Component		X 0.10
F.	No-Load Loss Component		1
G.	*Total Losses		**22**
	Note 1. Differential Loss = Losses at rated MW and rated power factor - losses and MW at unity power factor.		
H.	Average Generation (MW)		9,280
I.	MVAR usage (August 10th 1996) MVAR		1,647
J.	Generation (August 10, 1996) (MW)		5,040
K.	Total Max MVARS (available machine data)		**6,597**
L.	MAX Actual MVARs = (I /J) X A		5,773
M.	Average MVARS = (L/A) X H		2,509
N.	Average Losses (kW-hr) = (G/K X M) X 8760		71,638
O.	Value of Energy (mills/kW-hr)		**27.33**
P.	**Total Cost (N X O)/1000**	**$**	**1,958**

**Some values may not appear to total 100%. This is due to rounding.*

Section 4.4.3 - Table 14
Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy by Customer Groups

		A	B	C	D	E	F
				$ Millions			
		ALLOCATIO N FACTOR 2/	2005 ACTUAL	2006 EXPECTE D	2008 EXPECTE D WITH CURREN T NON-FEDERAL GENERA TORS	2008 ESTIMAT E WITH ADDITIO NAL NON-FEDERAL GENERA TORS	ESTIMAT ED IMPACT OF PROPOS AL
1	TBL compensation to PBL for reactive "within the band"		$ 23	$ 23	$ 20.4	$ 20.4	$ (20.4)
2	Payments to IPP Generators		$ -	$ 7.6	$ 11.1	$ 15.7	$ (15.7)
3	Payments to IOU Generators		$ -	$ -	$ -	$ 9.2	$ (9.2)
	Net Cost By Customer Group 1/						
4	Preference Customers net cost	55.2%	$ (10.3)	$ (6.1)	$ (3.0)	$ 4.6	$ (4.6)
5	IOU/DSI net cost	23.3%	$ 5.4	$ 7.1	$ 7.4	$ 1.3	$ (1.3)
6	Extra-regional customer net cost	11.0%	$ 2.5	$ 3.4	$ 3.5	$ 5.0	$ (5.0)
7	Marketers/non-federal generators net cost	10.5%	$ 2.4	$ (4.4)	$ (7.8)	$ (11.0)	$ 11.0
8	Total customer net cost	100.0%	$ -	$ -	$ -	$ -	$ -
							$ -
9	Total Cost w/non-federal payments		$ 23.0	$ 30.6	$ 31.5	$ 45.3	$ (45.3)
10	**Net Cost to Regional Ratepayers (Line 4 + Line 5)**		**$ (4.9)**	**$ 1.1**	**$ 4.4**	**$ 6.0**	**$ (6.0)**

1/ GSR compensation less incremental increase in cost of GSR transmission purchases
2/ See Attachment 2 "Custbreakout" for list of customers in each grouping.
3/ Allocation of reactive payment cost across customer groups based on actual FY 05 TBL billing determinants. (See Table 16)
4/ SeeTable 17 "ReactiveCostEst" for FY 06 and FY 08 estimated annual reactive payments to current non-Federal generators.
5/ See Table 18 "Add.Gens" for list of additional IPP and IOU generators filing for reactive and the estimated payment amount.

Lines 1 through 3 show TBL's compensation to PBL and IPP and IOU generators for within the band reactive; line 9 is the sum of lines 1 through 3 and represents TBL's total reactive payment. Lines 4 through 7 show the net cost of these reactive payments to regional ratepayers. Line 10 represents the total net cost to the Region, which consists of Preference Customers, IOUs and DSIs (Lines 4 and 5).

When TBL compensates PBL for inside the band reactive, PBL treats this payment as a revenue credit which reduces the overall revenue requirement. Preference customers benefit through a reduction in PBL's cost-based rates. The cost of this reactive payment is distributed to all customer groups through TBL's GSR rate. Using the allocation factors in column A, which are based on FY 05 actuals, Preference Customers must pay for 55.2 percent of the reactive payment to PBL through TBL's GSR rate but they receive 100 percent of the benefit, of PBL being compensated inside the band, due to a reduction in their power rates. In FY 05, TBL compensated only PBL for inside the band reactive, and the benefits to Preference Customers was $10.3M.

Compensating IPPs for inside the band reactive increases the net cost to the region. Regional ratepayers experience no benefit from making reactive payments to IPPs through reduction in power purchase costs and must incur the cost of these reactive payments through increases in TBL's GSR rate. IPPs however benefit from this arrangement since they receive reactive compensation from TBL and the majority of the cost of these reactive payments are absorbed by other customer groups.

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
Albany Research Center - DOE	Alcoa, Inc.	BC Powerex	Avista Energy, Inc.
Alder Mutual Light Company	Avista Corp - WWP	Calpine Energy Services	BP West Coast Products
Asotin County PUD	Columbia Falls Aluminum	Mirant Americas Energy	Calpine Energy Services
Benton County PUD No 1	Idaho Power Company	Sierra Pacific Power	Cargill Power Markets LLC
Benton PUD	Kaiser Aluminum	TransAlta Energy Mktg US	Chehalis Power Generating
Benton Rural Electric Association	Northwestern Energy LLC	TransCanada Energy Ltd.	Chelan County PUD-CHPM
Big Bend Electric Cooperative	PacifiCorp	Turlock Irrigation District	Columbia Energy Partners
Blachly-Lane County Cooperative	Port Townsend Paper Corp		Constellation Energy
Bonneville PBL	Portland Gen Marketing		Coral Power
Canby Utility Board	Portland General Electric		Frederickson Power LP
Central Electric Cooperative	Puget Sound Energy		Goldendale Energy Center
Central Lincoln PUD	Sierra Pacific Power		Hermiston Power Partnership
Central Montana Electric Power Coop			J Aron & Company
Chelan County PUD No 1			Morgan Stanley
City of Albion			North Point Energy Solutions
City of Ashland			Portland Gen Marketing
City of Bandon			PPM Energy, Inc.
City of Blaine			Sempra Energy Trading
City of Bonners Ferry			Suez Energy Marketing
City of Burley			
City of Cascade Locks			
City of Centralia			
City of Cheney			
City of Chewelah			
City of Coulee Dam			
City of Declo			
City of Drain			
City of Ellensburg			
City of Forest Grove			
City of Heyburn			
City of Klamath Falls			
City of McCleary			
City of McMinnville			
City of Milton-Freewater			
City of Minidoka			
City of Monmouth			
City of Plummer			
City of Port Angeles Light Dept.			
City of Richland			
City of Rupert			
City of Soda Springs			
City of Springfield Utility Board			
City of Sumas			
City of Troy			
Clallam County PUD No. 1			
Clark Public Utilities			
Clatskanie PUD			
Clearwater Power Company			
Columbia Basin Electric Cooperative			
Columbia Power Cooperative			
Columbia River PUD			
Columbia Rural Electric Association			
Consolidated Irrigation District No. 1			
Consumers Power Inc.			
Coos-Curry Electric Cooperative			
Cowlitz County PUD No. 1			
Douglas Electric Cooperative			
East End Mutual Electric Cooperative			
Elmhurst Mutual Power & Light Company			
Emerald PUD			
Energy Northwest Inc. (WPPSS)			
Eugene Water & Electric Board			
Fall River Rural Electric Cooperative			
Farmers Electric Cooperative			

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
Ferry County PUD No. 1			
Flathead Electric Cooperative			
Franklin County PUD No 1			
Glacier Electric Cooperative			
Grant County PUD No. 2			
Grays Harbor County PUD			
Harney Electric Cooperative			
Hermiston Energy Services			
Hood River Electric Cooperative			
Idaho County Light & Power Cooperative			
Inland Power & Light Company			
Kittitas County PUD No. 1			
Klickitat			
Kootenai Electric Cooperative			
Lakeview Light & Power Company			
Lane Electric Cooperative			
Lewis County PUD No. 1			
Lincoln Electric Cooperative			
Longview Aluminum LLC			
Lost River Electric Cooperative			
Lower Valley Power & Light Inc.			
Mason County PUD 1			
Mason County PUD 3			
Midstate Electric Cooperative Inc.			
Missoula Electric Cooperative			
Modern Electric Water Company			
Nespelem Valley Electric Cooperative			
Northern Lights Inc			
Northern Wasco County PUD			
Ohop Mutual Light Company			
Okanogan County Electric Cooperative			
Okanogan County PUD No 1			
Orcas Power & Light Cooperative			
Oregon Trail Cooperative			
Pacific County PUD No. 2			
Pacific Northwest Gen			
Parkland Light & Power Company			
Pend Oreille County PUD			
Peninsula Light Company, Inc.			
Port of Seattle/SeaTac Airport			
Raft River Rural Electric Cooperative			
Ravalli County Electric Cooperative			
Riverside Electric Company Ltd.			
Salem Electri Cooperative			
Salmon River Electric Cooperative			
Seattle City Light			
Skamania County PUD No 1			
Snohomish County PUD No 1			
Southern Montana Electric Coop			
Southside Electric Lines Inc.			
Surprise Valley Electric Cooperative			
Tacoma Power			
Tanner Electric Cooperative			
Tillamook County PUD			
Town of Eatonville			
Town of Milton			
Town of Steilacoom			
Umatilla Electric Cooperative			
Umpqua Indian Utility Coop			
United Electric Coop			
US Air Force (Fairchild)			
US Department of Navy (Bangor)			
US Department of Navy (Jim Creek)			
US Dept of Energy (Richland)			
US Navel Shipyard Bremerton			

Section 4.4.3 - Table 15

Regional Stakeholder Impacts of Costs of Current and Proposed Generation Supplied Reactive Power Policy - Customer Group Breakout

Preference Customers	IOU/DSI	Extra-Regional	Markets/Non-Federal Generators
USBIA - Mission Valley Power			
USBIA - Wapato			
Vera Irrigation District No 15			
Vigilante Electric Cooperative			
Wahkiakum County PUD No 1			
Wasco Electric Cooperative			
Wells Rural Electric Cooperative			
West Oregon Electric Cooperative			
Whatcom County PUD No 1			

Section 4.4.3 - Table 16
Generation Supplied Reactive (GSR) Effective Billing Determinants (MW-yrs)

	IM	IR	PTP_LT	IS_LT	NT	FPT	PTP_ST	IS_ST	TOTAL	% of Total
Preference Customers	-	-	8,896	2,416	5,286	92	867	23	**17,581**	**56%**
IOU/DSI	6	4,414	958	-	44	1,632	161	63	**7,278**	**23%**
Extra-Regional Customers	-	-	842	1,722	-	-	230	546	**3,339**	**11%**
Marketer/Non-Federal Generators	-	-	2,665	454	-	-	22	174	**3,314**	**11%**
TOTAL	**6**	**4,414**	**13,361**	**4,591**	**5,330**	**1,725**	**1,280**	**807**	**31,513**	**100%**

Section 4.4.3 - Table 17

Generation Supplied Reactive (GSR) Reactive Cost Estimates
Effective Billing Determinants (MW-yrs)

Generator	Starting Date	Original Request	FY 06 Expected Annual Payment 1/	FY 08 Expected Annual Payment 2/
Centralia	December, 2004	$1,115,003	$802,194	$891,327
Big Hanaford	October, 2005	$3,257,435	$759,240	$1,898,100
Chehalis	August, 2005	$3,677,151	$2,505,027	$3,677,151
Hermiston	August, 2005	$1,656,077	$1,242,058	$1,656,077
Goldendale	August, 2005	$1,246,501	$747,901	$1,246,502
KFalls	October, 2005	$2,375,767	$1,763,269	$1,749,786
Total		**$13,327,935**	**$7,819,689**	**$11,118,942**

1/ The rates for Centralia, K.Falls, Big Hanaford, and Hermiston are final. Goldendale in process of submitting to FERC.
2/ Derived by removing service factors from FY 06 IPP reactive payments.

Section 4.4.3 - Table 18

Additional Generators Generation Supplied Reactive Costs
Potential Generators that may file FERC GSR Rates

Note: Excludes hydro, wind, and small generators (cost too low to file)

Generator	MW Capacity	Owner 2/	Note
Lancaster	280	IPP	
Cherry Point	600	IPP	Planned for 2008
Fredrickson	270	IPP	Puget/Benton/Grays H/Franklin tolling agreement
Boardman	550	Reg Util	PGE/PNGC
Coyote Spr 1	250	Reg Util	PGE
Coyote Spr 2	250	Reg Util	Avista
Hermiston PAC	480	Reg Util	PAC
River Road	248	Reg Util	Clark
Beaver	531	Reg Util	PGE
SUM - MW	3,459		
Average Cost/MW 1/	4,000		
Total Charge to TBL	**$13,836,000**		

1/ Use average per unit rate calculated below

Current FERC filings			Without Service Factor	Per Unit
Goldendale	250	747,900	1,246,500	4,986
Hermiston	536	1,242,000	1,656,000	3,090
Klamath Cogen	484	1,662,000	1,787,097	3,692
Klamath Peaker	100	101,000	404,000	4,040
Sum	1370	3,752,900	5,093,597	3,718
Average $/MW		2,739	3,718	
			ROUND TO $4000/MW	

Cost Assumptions:
1. Based on rates filed with FERC for recent CTs. Not expected to change much when final.
2. No heating loss for these filings, but may be included after 10/07.
3. Did not use Chehalis or Big Hannaford as filed rate is high and expected to be reduced.
4. Service factor adjustment excluded as this is not expected to be used after 10/07.

2/ IPP ownership assumes no regional benefits from reactive charge.
Regional utility ownership assumes that these entities will past on reactive charge to their regional customers.

Section 4.4.3 - Table 19

Reactive Revenue Risk Analysis

The table below illustrates the planned net revenue for risk model output from an expected value of $12.5 milliion of revenues received over the last two years of the power rate period. These are estimates for the purpose of setting final power rates.

	FY07	FY08-09	Delta
Avg. Annual PNRR	$97 million	$108 million	$11 million
3-Year Avg. Rate	30.34 mills	30.52 mills	0.18 mills
Annual Avg Rates			
FY 2007	32.22 mills	32.45 mills	0.23 mills
FY 2008	30.52 mills	30.64 mills	0.12 mills
FY 2009	28.29 mills	28.48 mills	0.19 mills

1 BPA assumed TBL would compensate PBL for full embedded costs of $24 million for FY 2007.

2 BPA assumed that it was equally likely that annual reactive power revenues from TBL could be any value between $4 and $20 million per year, or expected value of $12.5 million, for FY 2008-2009. *See* BPA's Supplemental Power Proposal WP-07-E-BPA-28-29.

3 As the table shows, this increases the annual PNRR by an average of $11 million, with a corresponding average annual rate increase of 0.18 mills/kwh. The rate effect is largest in FY 2007.

4.4.4 Generation Dropping

Section 4.4.4 - Table 1
Generation Dropping
Incremental Equipment Deterioriation / Replacement or Overhead

	Equipment	% Life Reduction/Drop	Cost of Major Overhaul	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	$660,000	$264
2	**Main Power Transformer** (Equal to Replacement)	0.015%	$7,532,000	$1,284
3	**Generator** (Rewinding)	0.27%	$16,764,000	$45,263
4	**Turbine** (Refurbished)	0.24%	$1,320,000	$3,170
5	**500 kV Cable** (Replacement)	0.055%	$3,762,000	$2,070
6	**Total Annual Cost**			**$52,051**

Note: Text in parens indicates work needed to correct assumed deterioration and/or failure of equipment.

Section 4.4.4 -Table 2
Generation Dropping
Incremental Routine O and M Costs

	Equipment	% Increase O&M/Drop	Annual O&M Cost	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	$6,522	$3
2	**Main Power Transformer** (Equal to Replacement)	0.015%	$75,331	$12
3	**Generator** (Rewinding)	0.27%	$594,000	$1,604
4	**Turbine** (Refurbished)	0.24%	$594,000	$1,426
5	**500 kV Cable** (Replacement)	0.055%	$281,779	$154
6	**Total Annual Cost**			**$3,198**

Section 4.4.4 - Table 3
Generation Dropping
Incremental Value of Lost Revenue during Replacement or Overhaul

	Equipment	Probability	Months Downtime	Downtime Costs	Cost/ Drop
1	**500 kV Circuit Breaker** (50 % of Replacement)	0.04%	0	$0	$0
2	**Main Power Transformer** (Equal to Replacement)	0.015%	1	$2,380,000	$428
3	**Generator** (Rewinding)	0.27%	18	$42,840,000	$115,668
4	**Turbine** (Refurbished)	0.24%	16	$38,080,000	$91,392
5	**500 kV Cable** (Replacement)	0.055%	1	$2,380,000	$1,310
6	**Total Annual Cost**				**$208,798**

Section 4.4.4 - Table 4
Generation Dropping
Summary Costs for Rate Period

	Generation Dropping	Total
1	Incremental Maintenance Costs (Table 1)	$52,051
2	Deterioriation and Risk Replacement Costs (Table 2)	$3,198
3	Lost Revenues (Table 3)	$208,798
4	Subtotal	$264,047
5	**Average Generation Drops (1.5 * Line 4)**	**$396,071**

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4.4.5 Station Service

Section 4.4.5 - Table 1
Station Service Analysis

Substation	KVA Rating	Monthly Historic Usage	Notes
Big Eddy / Celilo		1597750	
Ross Complex		1749300	
Large			
Alvey	2267	96923	
Bell	2250	149000	
Snohomish	1250	78000	
Olympia	1100	132738	
Covington	946	108333	
Pearl	875	28067	
Longview	825	38317	
McNary	800	108717	
Chemawa	725	18140	
Anaconda	600	42910	
Columbia	600	18292	
John Day	500	65896	
Santiam	400	25740	
St. Johns	310	15858	
Port Angeles	300	49920	
Valhalla	300	17592	
Fairview	300	12560	
Subtotal	**14,348**	**1,007,003**	**9.6% Load Factor**
Medium			
Oregon City	225	13663	
Walla Walla	150	6919	
Raymond	150	5808	
LaGrande	150	5663	
Ellensburg	100	3897	
Grandview	75	5605	
Roundup	75	5708	
Boardman	75	1595	
Drain	65	1654	
Reedsport	55	3922	
Subtotal	**1,120**	**54,434**	**6.7% Load Factor**

Substation	KVA Rating	Monthly Historic Usage	Notes
Small			
Valley Way	50	1984	
Salem Alumina	45	2604	
Sappho	45	2363	
Lookout Point	40	3387	
The Dalles	38	2657	
Carborundum	35	3187	
Bandon	25	1746	
Gardiner	25	1402	
Creston	15	1122	
Clatskanie	10	1771	
Newport	10	1735	
Hauser	10	1525	
Duckabush	10	1192	
Benton City	10	1076	
Ione	5	1028	
Subtotal	**373**	**28,779**	**10.6% Load Factor**
TOTAL	**15,473**	**1,062,465**	**9.4% Load Factor**

	Installed kVa	Load Factor 9.40% kWh	
Big Eddy / Celilo		1,597,750	
Ross Complex		1,749,300	
Large	36,936	2,534,548	
Medium	5,148	353,256	
Small	1,946	133,535	
TOTAL		**6,368,389**	**kWh / month**

(6,368,389 / 1,000) *27.33 mills * 12 months = **$2,088,577 Total Annual Cost**

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4.5 Segmentation of COE/USBR Transmission Facilities

4.5.1 COE Facilities

4.5.2 Columbia Basin Facilities

4.5.3 Other USBR Facilities

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4.5.1 COE Facilities

Section 4.5.1 - Table 1
COE Transmission Segmentation

BONNEVILLE DAM

A major rehab was done to the Bonneville Dam switchyard in 1999.
The current plant in service costs provided by the COE are:

Prop ID	Plant Item	Book Cost
BONNE-13361	power transformers	27,997,022
BONNE-13358	switchyard circuit breaker	1,499,685
BONNE-13559	switchyard circuit breaker	1,499,960
BONNE-13360	switchyard circuit breaker	1,500,514
	Total	**32,497,181**

The power transformers are assigned to generation.
Circuit breakers are allocated to Network & Generation Integration based on use.
There are six 115 kV circuit breakers; two Generation Integration and four Network.

BONNE-13358	switchyard circuit breaker	1,499,685
BONNE-13559	switchyard circuit breaker	1,499,960
BONNE-13360	switchyard circuit breaker	1,500,514
	Total Circuit Breakers	4,500,159

Network Allocation (4/6) **3,000,106**

4.5.2 Columbia Basin Facilities

Section 4.5.2 - Assumptions

COLUMBIA BASIN TRANSMISSION COST

Purpose - to split USBR Columbia Basin project transmission costs into the appropriate segments, including Network, Delivery, and Generation Integration (GI).

GI is transmission facilities between the generator and the Network station, including step-up transformers, powerhouse lines or cables, and switching equipment at the Network station for the powerhouse line. The remainder is Network.

The USBR does not have investment data to the level of major piece of equipment. The data is available by major group, as 500 kV switchyard. These costs will be allocated to GI and Network segments based on BPA typical facility costs for the major equipme

The typical costs will be developed for major divisions, as the 500 kV switchyard. The ratio for Network will be developed based on the cost of the equipment that is Network as a ratio of the total cost.

Assumptions/Method

1. Interest during construction (IDC) and other general costs will be allocated based on investment.

2. Typical costs as noted on investment ratio sheet.

3. USBR transmission starts at the high side of the generator breaker (low side of step-up transformer) through the substation per Chris Christoferson/USBR Coulee. This includes the step-up transformers, but not the powerhouse switching.

4. Delivery: The 115/13.8 kV facilities at Coulee are used for station service and to deliver power at 13.8 kV to Grant, Coulee City, and Nespelem Valley at Lonepine. An allocation of costs between uses is necessary.

5. The 500 kV additions for the Coulee-Bell line are not included in the investment.

6. Investment does not include construction work in progress. Use added below:

IDC % adder for electric plant for FY04:	**0.117891472**
IDC =	**108,552,675**
Total electric plant =	**1,029,337,473**

Section 4.5.2 - Table 1
COLUMBIA BASIN COSTS (Grand Coulee) SUMMARY

Segment	Investment	
Network	$ 41,914,344	23.4%
Generation Integration	136,295,305	76.2%
Delivery	621,883	0.3%
Total	**$ 178,831,533**	

THIRD POWERHOUSE (500 kV Facilities):

Segment	Investment		From USBR sheet 13.034
Network	$ 16,491,112	15.7%	93,823,188
Generation Integration	88,393,024	84.3%	Plus IDC of 11.78%
Total	**$ 104,884,136**		104,875,560

FIRST & SECOND POWERHOUSE & OTHERS:

Segment	Investment	
Network	$ 25,423,232	34.4%
Generation Integration	47,902,281	64.8%
Delivery	621,883	0.8%
Total	**$ 73,947,397**	

NOTES:
Investment includes IDC.
O&M for transmisssion only; does not include step-ups.
No updated O&M costs.

Section 4.5.2 - Table 2
COLUMBIA BASIN COSTS (Grand Coulee)
BOR data for investments as of 9/30/2004

Power	Cost	Notes/Source		
Multi-purpose		From BOR assets accounts		
Electric Plant	$1,029,337,473	**1/** From BOR assets accounts		
Total	**$1,029,337,473**			
Electric Plant	$964,537,093	BOR Financial Structure/asset account		
Irrigation Assignment	-5,655,456	**2/** From BOR assets accounts		
Total	**$958,881,637**			
13.031 Pump Generator Switchyard	4,742,053	**3/** from BOR Financial Structure		$4,742,053
Percent Network	None	All GI		11.789%
			GI	$5,301,101
13.034 500kV & Other Switchyard	$93,823,183	**3/** from BOR Financial Structure		
500kV cables **6/**	-29,897,939	Not sub-assume 500kV GI		
Net sub	**63,925,244**			
Percent Network	23.1%	Base on typical costs		
Network Allocation	14,751,979		GI	$79,071,204
Percent for IDC **5/**	11.789%	from BOR Electric costs		11.789%
Total Network-500kV	**$16,491,112**			$88,393,024
13.035 Modified Left Switchyard	$60,850,641	**4/** from BOR Financial Structure		
Lines **7/**	-14,775,732	Not sub - assume 230kV GI		
Net sub	**$46,074,909**			
Percent Network	0	Base on typical costs		
Network Allocation	22,742,129		GI	$38,108,512
Percent for IDC **5/**	11.789%	from BOR Electric costs		11.789%
Total Network-Left	**$25,423,232**			$42,601,180
TOTAL NETWORK	**$41,914,344**		GI	$136,295,305
Percent Delivery	1.2%	Left Yard only 115/12 kV		
Percent for IDC **5/**	0	from BOR Electric costs		
Total Delivery	**$621,883**			

NOTES:
1/ Assume all transmission is in electric plant.
2/ Assume this is in pump gen switchyard and power plant.
3/ Assume this includes all 500 kV line and sub costs; IDC not included.
4/ Assume this includes all 230 kV and other transmission costs; IDC not included.
5/ IDC is allocated based on ratio of investment to total investment.
6/ Assumes cables are all in 500 kV yard and can be removed as a group.
7/ Assumes all lines are part of left yard and can be removed as a group.

Section 4.5.2 - Table 3
NETWORK INVESTMENT RATIO-ASSIGNMENT BASED ON TYPICAL SUB COSTS
BPA typical cost of facilities - 12/11/98

Items	Total	Network	Gen Int	Unit Cost ($000)	Total	Network	Gen Int	Delivery	Note
500 kV Switchyard									
500 kV terminal (1&1/2)	11	5	6	$ 4,500	$ 49,500	$ 22,500	$ 27,000		
Step-ups 7-800 MVA	6		6	8,000	48,000	-	48,000		3/
Total					**$ 97,500**	**$ 22,500**	**$ 75,000**	**-**	
500kV - Network % =	23.08%		% w/o step-ups		45.5%				
Left Switchyard (includes 230 & 115 yards)									
230 kV PCB 1/	22	17	5	$ 560	$ 12,320	$ 9,520	$ 2,800		
500/230 tx 1200MVA	1	1		9,800	9,800	9,800	-		
230/287kV tx	1	1		2,600	2,600	2,600	-		
230/115 tx 230MVA	1	1		2,600	2,600	2,600	-		
115kV PCB	7	7		375	2,625	2,625	-		
Delivery - 20 MVA tx	2			1,010	2,020		1,616	404	2/
Delivery- feeder terminals	11			130	1,430		1,170	260	2/
Step-ups 1-125MVA	18		18	1,200	21,600	-	21,600		4/
Total					**$ 54,995**	**$ 27,145**	**$ 27,186**	**$ 664**	
Left Yard- % Network	49.4%		Network % w/o step-ups		81.3%		% Delivery	1.2%	
							% Del w/o step-up	2.0%	

1/ Some breakers are for bus tie, etc.; these are Network.

2/ Delivery transformer split 20% to Delivery; based on estimate of 25 MVA with low and hi side PCB.
Delivery terminals based on 12.5kV feeder cost; split based on 2 for Delivery and rest for station service.

3/ Cost of 500 kV step-ups are similar to 500/230, so cost of 700MVA without breakers is used.

4/ Cost of 230 kV step-ups are similar to 230/69, so cost of 75MVA without breakers is used.

Note: Coulee-Bell additions not in plant for FY04 so not included in allocation.

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4.5.3 Other USBR Facilities

Section 4.5.3 - Table 1
USBR SEGMENTATION - OTHER PROJECTS
Based on data from USBR - Boise, ID office

PROJECT	TRANSMISSION INVESTMENT 2/	NETWORK	GENERATION INTEGRATION	DELIVERY
Hungry Horse	$ 11,854,647	$ 2,477,090	$ 9,377,557	
Boise 1/	953,782	-	953,782	
Yakima(Rosa)	3,209,543	-	3,209,543	
Green Springs	176,398	-	176,398	
Minidoka	1,602,312	846,291	756,020	
Palisades	2,101,041	391,336	1,333,442	376,262
Total	$ 19,897,721	$ 3,714,718	$ 15,806,741	$ 376,262

Segment investment is total investment times segment % determined below.
Segment percent is estimated using 1998 typical BPA facility costs as proxy.

1/ Includes Anderson Ranch and Black Canyon.
2/ Total from BOR Electric Plant In Service, sub account 13 with IDC allocation.

SEGMENT PERCENTAGES FOR MULTI-SEGMENT PLANTS

Hungry Horse:

Item	Cost	Network	Gen Int
2-230kV terminals	$ 1,120,000	$ 1,120,000	-
2-230kV terminals	1,120,000	-	1,120,000
2-180MVA step-ups	3,120,000	-	3,120,000
Total	$ 5,360,000	$ 1,120,000	$ 4,240,000
Percent of total		20.9%	79.1%

Step-up transformer cost based on 230/69kV 75 MVA w disconnects.

Minidoka-Palisades:

Minidoka sub	Cost	Network	Gen Int	Delivery
5-138kV terminal	$ 2,250,000	$ 1,500,000	$ 750,000	
1 Step-up to 138kV	590,000		590,000	
Total	$ 2,840,000	$ 1,500,000	$ 1,340,000	
Percent of total		52.8%	47.2%	0.0%

Palisades:	Cost	Network	Gen Int	Delivery
9-115kV terminals	$ 3,375,000	$ 1,265,625	$ 1,687,500	$ 421,875
4-35MVA step-ups	2,360,000		2,360,000	
10MVA 115/12.5kV	1,060,000		265,000	795,000
Total	$ 6,795,000	$ 1,265,625	$ 4,312,500	$ 1,216,875
Percent of total		18.6%	63.5%	17.9%

NOTES:
Minidoka terminals - use 115kV terminal cost of $375,000;
Minidoka terminals - 4 Network, 2 Generation Integration, 1 bus tie
Minidoka step-up - use 115/34.5kV 25 MVA transformer cost
Palisades - 9 PCB/8 terminals - 4 GI, 3 Net, 1 Del
Palisades step-ups - use 115/34.5kV 25 MVA transformer cost
Palisades - delivery is for Lower Valley and station service
Base delivery tx on cost of 115/12.5 sub 25MVA
Split station servcie facilities 25% to delivery & 75% to station service/GI

4.6 UAI AND EXCESS FACTORING CHARGES

Documentation Table 4.6.1
Sample Derivation of UAI Charges (w/minimum) for Demand by Month
Historical Period August 2--4 through July 2005

	A	B	C	D
Month	**ISO NW1 ($/kW/mo)**	**ISO NW3 ($/kW/mo)**	**Minimum UAI charge (3x Prop PF-07 demand chg 2/ ($/kW/mo)**	**Effective charge (max of Cols. A, B, or C) ($/kW/mo)**
	Index based Charges 1/			
Aug-04	$1.09	$3.19	$10.17	$10.17
Sep-04	$1.09	$1.09	$10.17	$10.17
Oct-04	$1.89	$1.89	$7.02	$7.02
Nov-04	$1.35	$1.35	$9.21	$9.21
Dec-04	$1.58	$1.58	$9.21	$9.21
Jan-05	$4.33	$4.33	$8.61	$8.61
Feb-05	$3.85	$3.85	$8.10	$8.10
Mar-05	$4.00	$4.00	$7.23	$7.23
Apr-05	$5.97	$5.97	$5.94	$5.97
May-05	$4.84	$4.84	$5.88	$5.88
Jun-05	$3.33	$3.33	$7.35	$7.35
Jul-05	$6.06	$6.06	$9.51	$9.51

1/ Sum of hourly ISO market clearing spinning reserve capacity prices for all HLH's
2/ Minimum UAI demand charge is in this colum are three (3) times the proposed PF demand charge

Documentation Table 4.6.2 Sample Derivation of UAI Charges (w/minimum) for Energy by month
Historical period August 2004 through July 2005

	A	B	C	D
	Indexed based charges			
Month	DJ mid-C Firm ($/MWh)	ISO Supplemental energy NP-15 ($/MWh)	Minimum UAI charge ($/MWh)	Effective Charge (max of Cols A, B, C)
Aug-04	$61.59	$159.57	$100.00	$159.57
Sep-04	$44.42	$100.25	$100.00	$100.25
Oct-04	$60.68	$156.30	$100.00	$156.30
Nov-04	$54.27	$147.07	$100.00	$147.07
Dec-04	$57.57	$148.37	$100.00	$148.37
Jan-05	$60.12	$170.50	$100.00	$170.50
Feb-05	$49.90	$103.64	$100.00	$103.64
Mar-05	$57.57	$135.38	$100.00	$135.38
Apr-05	$57.61	$141.10	$100.00	$141.10
May-05	$48.44	$142.08	$100.00	$142.08
Jun-05	$51.67	$124.60	$100.00	$124.60
Jul-05	$77.36	$162.33	$100.00	$162.33

DOCUMENTATION TABLE 4.6.3 SAMPLE Derivation of Within-Day Excess Factoring Charges, by Month
Historical Period August 2004 through July 2005

	A	B	C	D	E	F
	HLH Within-Day Excess Factoring Charges			LLH Within-Day Excess Factoring Charges		
Month	Within-Day Deltas ISO Supplemental Energy (NP-15) ($/MWh)	Minimum Within-Day Excess Factoring Charges ($/MWh)	Effective Charge (Max. of Cols. A and B)	Within-Day Deltas Supplemental Energy (NP-15) ($/MWh)	Minimum Within-Day Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. D and E) ($/MWh)
Aug-04	$56.30	$5.00	$56.30	$99.08	$5.00	$99.08
Sep-04	$79.46	$5.00	$79.46	$90.38	$5.00	$90.38
Oct-04	$79.33	$5.00	$79.33	$126.26	$5.00	$126.26
Nov-04	$101.21	$5.00	$101.21	$92.83	$5.00	$92.83
Dec-04	$139.89	$5.00	$139.89	$100.18	$5.00	$100.18
Jan-05	$153.24	$5.00	$153.24	$134.52	$5.00	$134.52
Feb-05	$80.75	$5.00	$80.75	$67.26	$5.00	$67.26
Mar-05	$134.71	$5.00	$134.71	$129.21	$5.00	$129.21
Apr-05	$109.90	$5.00	$109.90	$116.99	$5.00	$116.99
May-05	$145.09	$5.00	$145.09	$102.31	$5.00	$102.31
Jun-05	$123.51	$5.00	$123.51	$103.61	$5.00	$103.61
Jul-05	$149.02	$5.00	$149.02	$102.10	$5.00	$102.10

DOCUMENTATION TABLE 4.6.4 SAMPLE Derivation of Within-Month Excess Factoring Charges, by Month 1/
Historical Period August 2004 through July 23005

	A	B	C	D	D	F	G	H
	HLH "Within Month" Excess Factoring Charges				LLH "Within Month" Excess Factoring Charges			
	Indexed Based Charges				Indexed Based Charges			
Month	ISO Suplemental Energy Index (NP-15) ($/MWh)	DJ Mid-C Index (Onpeak firm) ($/MWh)	Minimum Within-Month Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. A, B, C) ($/MWh)	ISO Suplemental Energy Index (NP 15) ($/MWh)	DJ Mid-C Index (Onpeak firm) ($/MWh)	Minimum Within-Month Excess Factoring Charge ($/MWh)	Effective Charge (Max. of Cols. A, B, C) ($/MWh)
Aug-04	$36.41	$25.36	$5.00	$36.41	$123.96	$23.22	$5.00	$123.96
Sep-04	$54.10	$9.41	$5.00	$54.10	$73.37	$7.80	$5.00	$73.37
Oct-04	$68.34	$23.63	$5.00	$68.34	$113.27	$21.09	$5.00	$113.27
Nov-04	$109.55	$14.19	$5.00	$109.55	$74.17	$12.68	$5.00	$74.17
Dec-04	$95.79	$17.12	$5.00	$95.79	$75.06	$17.25	$5.00	$75.06
Jan-05	$119.31	$18.26	$5.00	$119.31	$122.29	$13.94	$5.00	$122.29
Feb-05	$66.39	$5.86	$5.00	$66.39	$33.93	$9.35	$5.00	$33.93
Mar-05	$94.51	$10.93	$5.00	$94.51	$99.34	$15.24	$5.00	$99.34
Apr-05	$92.15	$13.48	$5.00	$92.15	$69.20	$16.92	$5.00	$69.20
May-05	$102.91	$32.25	$5.00	$102.91	$78.06	$33.23	$5.00	$78.06
Jun-05	$91.04	$19.47	$5.00	$91.04	$66.15	$19.58	$5.00	$66.15
Jul-05	$122.24	$41.46	$5.00	$122.24	$49.55	$31.64	$5.00	$49.55

1/ The 'Within-Month' deltas for the HLH within-month Excess Factoring are computed by subtracting the LOWEST average daily ISO or Mid-C HLH price (average of 16 hours) for the month from the HIGHEST average daily HLH price for the month. A corresponding calculation is performed to derive the LLH within-month Excess Factoring charge (24 hours on Sunday, 6 NERC holidays, and hours ending 1-6 and 23 -24 for all other days).

4.7 OMIT

4.8 OMIT

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4.9 ASC FORECAST

has been renumbered and can be found in Chapter 8

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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-07 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	37.03	36.82	0.38	0.04	0.06	0.01

Utility Number: # 33

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Utility Number: # 69	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	$1,035,622	$1,035,622				
Transmission	$712		$712			
Distribution	$59,107			$59,107		
Customer Service, Accounts & Sales						
Supervision	$12				$12	
Meter Reading	$18			$18		
Customer Records Collection	$54			$54		
Uncollectable Accounts	$4				$4	
Misc. Customer Accounts	$12				$12	
Customer Communication & Education	$9				$9	
Customer Assistance	$49				$49	
Advertising	$1				$1	
Administrative & General	$41,855		$497	$41,297	$61	
Total Interest/Debt Service Expense	$46,721		$556	$46,165		
Capital Projects Funded from Rates						
Production						
Transmission	$67,619		$67,619			
General	$18,698		$222	$18,476		
Other (Increases in inventory)	$2,281		$27	$2,254		
Taxes						
State Utility Tax	$45,972					
FICA	$3,966		$47	$3,913	$6	
State Privelege Tax	$24,261					
Other Taxes	$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	$423,071
Other Revenues	-$2,655		-$32	-$2,620	-$4	
BPA C&R Credit	-$14,355	-$14,355				
Conservation Augmentation Reimbursement	-$14,221	-$14,221				
Annual MWh Sales **29,115**						
Mills/kWh	43.02	34.59	2.37	3.63	0.00	2.44

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

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

Utility Number: # 87

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

Total energy sold Customer 1 39,018 MWh
Margin = $5.04/MWh

Total energy sold Customer 2 20,053 MWh
Margin = $4.49/Mh

Utility Number: # 93

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

Total energy sold Customer 1	110,588 MWh
Margin = $5.00/MWh	
Total energy sold Customer 2	202,967 MWh
Margin = $2.18/Mh	
Total energy sold Customer 3	2,173,245 MWh
Margin = $0.41/MWh	
Total energy sold Customer 4	623,470 MWh
Margin = $0.56/Mh	

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

Utility Number: # 99
Three large industrial customers are sold power under a special tariff schedule. Each customer is charged a margin of $387/month. Total annual MWh sales = 283,411 MWh. Margin = $0.049/Mh

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

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

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

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

Utility Number: # 113		Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power		$14,885,596	$ 14,885,596				
Generated Power		$242,706	$ 242,706				
Transmission		$1,444,368		$1,444,368			
Distribution		$1,862,469			$ 1,862,469		
Customer		$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

VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

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VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

Section 7(c)(3) of the Northwest Power Act provides that the Administrator shall adjust rates to the DSI customers "to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." The DSIs may provide two types of reserves: Supplemental Contingency Reserves and Stability Reserves. The BPA PBL's construct for procuring Supplemental Contingency Reserves (Supplemental Reserves) is described below.

The Northwest Power Pool (NWPP) MORC require BPA, as the control area operator, to carry reserves equal to 5 percent of online hydroelectric generation, 5 percent of online wind generation, and 7 percent of online non-hydroelectric generation. Up to half of this amount may be Supplemental Reserves, and the remainder must be Spinning Reserves responsive to frequency. Supplemental Reserves are defined as both offline generation fully available within 10 minute notice and interruptible load that can be offline within 10 minutes notice.

Supplemental Reserves is an ancillary service that a transmission provider must offer under the FERC pro forma tariff. This ancillary service is made up of both transmission inputs and generation inputs. As the transmission provider, TBL will procure the generation inputs, and may do so from any entity, including PBL, in order to provide this service. However, establishing a mechanism under which PBL may secure Supplemental Reserves from the DSIs does not preclude TBL from purchasing reserves directly from the DSIs.

At this time, PBL does not anticipate needing to purchase any Supplemental Reserves from DSI customers. The BPA FCRPS power system is capable of providing its own Supplemental Contingency Reserves under most circumstances. DSI provided Supplemental Reserves allows BPA to apply more of its generating capacity to serving load, which is especially important during cold snaps, court ordered spill, and other conditions where system flexibility is limited and of greater importance. In such an event that PBL does purchase Supplemental Reserves from a DSI, it will be reflected as an adjustment to the providing customer's IP-07 rate. The level of the credit will be negotiated on an individual customer basis. However, a maximum value that could be reflected in the credit is being proposed. This ceiling is $5.63 kW-month derived from an embedded cost methodology. The details of how this rate was developed can be found in Bermejo *et al*., WP-07-E-BPA-22.

PBL will require any Supplemental Reserves purchased from the DSIs to meet NERC, WECC, and NWPP criteria:

- The time delay between request for load to be interrupted and the agreed amount of DSI load to go offline, is less than or equal to 5 minutes.

- Once there is system disturbance, the interruptible load must be accessible prior to a request for reserves from other NWPP parties.

- The interruptible load is available to be offline for up to 60 minutes.

In addition to these required characteristics, the additional criteria identified below define when PBL may pay up to the maximum value for Supplemental Reserves. Once the required criteria are met the rate paid to a DSI will be negotiated on an individual customer basis, based on the following criteria:

- The extent to which BPA has discretion regarding when and how to use the product in satisfaction of obligations and in response to a qualifying system disturbance.

- Limitations on the number of times or total minutes the product can be utilized.

Pursuant to satisfying the above criteria BPA will satisfy its obligation to provide a reserves credit to the DSI through TBL's Transmission Contracts and the Stability Reserves Credit.

APPENDIX C

MARKET POWER ANALYSIS

GENERATION MARKET POWER ANALYSIS
FOR
BONNEVILLE POWER ADMINISTRATION
POWER BUSINESS LINE

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May 2005

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Summary and Conclusions

This report presents an assessment of Bonneville Power Administration's Power Business Line's (referred to as PBL in this report) ability to exert horizontal market power in its regional markets based on two market power screens adopted by the Federal Energy Regulatory Commission (FERC) in recent orders.[1] The two market power screens are the Pivotal Supplier screen and the Market Share screen. The Pivotal Supplier screen addresses whether the applicant can exercise market power unilaterally based on the ability of other suppliers to meet market demand. An applicant passes the Pivotal Supplier screen if wholesale sales during the peak month can be met without the applicant's uncommitted supplies. The Market Share screen addresses whether the applicant has a dominant position in the market based on its share of uncommitted supplies in the market during each of the four seasons. An applicant passes the Market Share screen if its share of uncommitted capacity is less than 20 percent.

The analyses use historical data for the 2003 calendar year, and examine two relevant regional markets.[2] The first is the BPA Transmission Business Line's (TBL) control area (BPA Control Area or BPAT) and its first-tier markets consisting of 16 connected control areas. The second market is the larger Pacific Northwest (PNW) region and its first-tier markets consisting of 3 connected control areas.[3]

The results of the analyses clearly show that PBL passes the two market power screens in both the BPA Control Area and the PNW. In terms of the Pivotal Supplier screen, our analysis indicates that PBL's dependable supplies are fairly well balanced with its firm long-term sales obligations during peak periods in 2003. In fact, PBL would be short 730 MW if it had to meet its total contract capacity obligations during the peak period of the year. While this result may appear to be counterintuitive, it is consistent with PBL's analysis of its loads and resources as reported in its recent "2003 Pacific Northwest Loads and Resources Study."[4] The study shows that PBL expects to be a net deficit supplier during the peak winter period assuming minimal hydro conditions and average loads. Adjusting for average hydro conditions and peak load conditions results in a similar

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[1] Although FERC has adopted the screens, it continues to refer to them as "interim" screens in light of the fact that FERC's rulemaking proceeding on market based rates (Docket No. RM04-7-00) is ongoing. As recently as February 27-28, 2005, FERC held a Technical Conference to consider, among other things, whether "the interim generation market power screens and approach to mitigation [should] be retained? If not, how should they be revised, or what should replace them?" Docket No. RM04-7-00, "Supplemental Notice of Agenda for Technical Conference," Attach. at 1 (Issued January 21, 2005). Thus, while FERC is actively implementing the two screens -in their present design- to assess utilities' generation market power, there is a possibility that FERC may modify the design of the screens or abandon them altogether. Accordingly, the analysis contained in this report implements the screens in their present design, as of the date of this document.

[2] FERC requires that applicants use unadjusted historical data for the most recent 12-month period in developing the market screens.

[3] For purposes of this analysis, the PNW is defined as the U.S. systems of the Northwest Power Pool (NWPP). See Appendix A for a list of control areas within the NWPP.

[4] Exhibit 2 of the report shows that BPA expects a deficit in its firm loads and resource balance during January and February of 2005 the peak load period in the BPA control area. The study is based on a minimal hydro availability (1937 Water Year) but the deficit is also based on average load levels. Additional hydro generation under normal year hydro conditions would be offset by an increase in PBL's load. Exhibit 5 of the report shows that there would also be a deficit of capacity during the months of January, February and April of 2005. Furthermore, BPA has had energy deficits during February in sixteen of the 50 years from 1929 to 1978 as shown in Exhibit 8 of the report.

supply shortfall. Independent of PBL's supply shortfall, Other Suppliers both within the BPA control area and in the larger PNW have significant amounts of uncommitted supplies, which allow them to satisfy the market's wholesale loads without reliance on PBL supplies. As a result, PBL passes the Pivotal Supplier screen in both regional market areas very easily.

In terms of the Market Share screen analysis, PBL's supply/demand balance leaves it with very limited uncommitted capacity relative to Other Suppliers during each of the four seasons of the year. In the BPA control area market, PBL's market share of the uncommitted capacity does not exceed 21 percent if one ignores the ability to import additional supplies into the market. Taking into account the ability of Other Suppliers to (1) import up to 6,500 MW of additional supplies into the BPA control area, and (2) redirect PBL's exports to customers in the control area,[5] PBL's market share of potential uncommitted supplies is, at the most, 9 percent in the Spring season, 7 percent during the Winter and Summer seasons, and 1 percent in the Fall season. PBL would still be able to pass the market share screen in all four season if Other Suppliers could only import up to 150 MW into the BPA control area each season. In the PNW market, PBL's market share of the market's uncommitted capacity does not exceed 15 percent even if imports are ignored. Therefore, PBL passes the Market Share screen in the PNW market without reliance on imports of additional supplies. Taking into consideration Other Suppliers' ability to import up to 6,500 MW of additional supplies into the PNW market and redirect up to 2,000 MW of exports, PBL's market share reduces to 7 percent in the Winter and Summer seasons, 6 percent in the Spring season and less than 1 percent in the Fall season.

Based on the results of these two Market Screen analyses, there should be the strong presumption that PBL does not possess market power. Instead of being a Pivotal Supplier, our market screen analyses show that PBL's dependable supply is fairly well matched to its long-term sales obligations during peak periods. It does not have any significant uncommitted long-term supplies with which to exert market power in the wholesale market during peak periods. PBL's ability to exert market power, either alone or in conjunction with other suppliers, also appears to be minimal, based on the result of the Market Share analysis. Given very reasonable assumptions about the BPA control area simultaneous transfer capability supported by TBL's studies, PBL's market share never exceeds 9 percent in any season in either the BPA control area or the PNW markets. PBL also passes the Market Share screens in the PNW market if imports are ignored, and in the BPA control area market if its transmission import capability exceeds 150 MW.

Section II of this report summarizes the FERC orders regarding the two Market Screens and presents an overview of the methodology used to arrive at our conclusions. Background information on BPA and its operations is presented in Section III. A study of the relevant geographic markets and first-tier control areas is summarized in Section IV. A more detailed market analysis of BPA control area, with all relevant data is presented in Section V. Section VI presents a detailed analysis of the PNW market, with all relevant data. Section VII presents our conclusions.

[5] The amount of imports by Other (non-PBL) Suppliers will depend on the amount of uncommitted capacity in adjacent control areas less the amount of transmission capacity allocated to PBL's long-term imports. In addition to increasing imports Other Suppliers who are scheduled to receive PBL's exports can reschedule those exports to customers in the control area, thereby increasing the amount of competitive supplies in the control area.

Methodology Overview and FERC Orders

In its "Order on rehearing and modifying interim generation market power analysis and mitigation policy,"[6] FERC adopted two new interim Market Power (MP) screens. The first is a Pivotal Supplier screen, which measures market power at peak times, particularly in spot markets. The presumption is that if the total demand in the market area can only be met with the applicant contributing some or all of its uncommitted supplies, then the applicant could extract significant monopoly rents during peak periods. The second is a Market Share screen that measures whether the applicant has a dominant position in the market based on its share of total uncommitted supplies for each of the four seasons. Market Share is an indicator of whether the applicant has unilateral market power and may indicate the presence of the ability to facilitate coordinated interaction with other suppliers. FERC describes the two screens as "indicative" because, if an applicant passes both screens, the presumption is that it does not have the ability to exercise market power either unilaterally or in coordinated interaction with other suppliers. If an applicant fails either screen, there is a presumption that it has market power. In either case the applicant or intervenors can provide evidence to disprove the presumption.

The Pivotal Supplier analysis is based on first calculating the uncommitted supplies of both the applicant and other suppliers available to compete for the wholesale load in the relevant market. This is a measure of supplies in the market not committed to meet firm long-term obligations such as utilities' native loads and long-term sales. Uncommitted supply is the difference between net supplies available and load obligations. Net supplies available equals the total nameplate capacity of generation owned or controlled through contracts and firm purchases, less operating reserves, and other capacity adjustments. Load obligations are the sum of native load commitments and long-term firm sales. The capacity available for wholesale sales is calculated by adding the total uncommitted capacity of the applicant and other suppliers within the market area to the capacity of potential imports from first tier markets (i.e., markets that are directly connected to the applicant's market area). The net uncommitted supply is then calculated as the capacity available for wholesale sales less the wholesale load. The wholesale load is estimated as the annual system peak load less the proxy for the native load obligation (i.e., the average of the daily native load peaks, excluding weekend days and holidays, during the month in which the annual peak load occurs). If the applicant's uncommitted capacity is less than the net uncommitted market supply, then the applicant passes the Pivotal Supplier screen.

The Market Share analysis also requires the calculation of the applicant and other suppliers' uncommitted capacity with some variations. The calculation is done for each of the four seasons, and the proxy native load is defined as the minimum peak day load for each season considered. Suppliers are also adjusted for any seasonal variations such as planned outages and long-term contract commitments.[7] The applicant's market share is then calculated based on its uncommitted capacity as a percent of the total uncommitted capacity available to serve the wholesale market. If the applicant's market share is less than 20 percent in each of the four seasons, then it passes the Market Share screen.

If an applicant is found to have market power, the applicant can: (1) propose a more robust market power study, referred to as the Delivered Price Test (DPT); (2) file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power; and/or (3) inform the Commission that it will adopt FERC's default cost-based rates or propose other cost-

[6] "Order on rehearing and modifying interim generation market power analysis and mitigation policy" (Issued April 14, 2004) 107 FERC ¶ 61, 018. [FERC's April 14, 2004 Order.]

[7] Planned outages are assumed to be zero in the Pivotal Supplier analysis.

based rates and submit cost support for such rates. Before the Commission considers the DPT, the applicant must be found to have "failed" one of the two "indicative" screens or so concede.

Various parties submitted requests for rehearing of the April 14, 2004 Order. In response, FERC issued "Order on Rehearing," on July 8, 2004.[8] In this order, FERC stood by its interim market power screens adopted in April, but sought to clarify implementation issues regarding the screens and the associated market-based rates process.[9]

The FERC Orders provide general guidance on the method and calculations for the market power screens analyses. FERC specifically allows applicants to make simplifying assumptions. For example, FERC states: "…. any applicant, regardless of size, has the option of making simplifying assumptions in its analysis where appropriate. Appropriate simplifying assumptions are those assumptions that do not affect the underlying methodology utilized by these screens."[10] In another section of its Order, FERC reminds applicants "…they may make appropriate simplifying assumptions that do not affect the underlying methodologies utilized by the generation market power screens."[11] Accordingly, when necessary or appropriate, the analysis contained herein incorporates simplifying assumptions. When there were choices for assumptions, conservative assumptions (i.e., assumptions likely to increase PBL's uncommitted capacity or market share) were made.

background information on bpa

BPA is a federal agency under the U.S. Department of Energy, established in 1937. BPA is the designated marketing agency for 31 Federal hydroelectric projects and some non-federal projects located in the PNW. BPA primary service area is the PNW comprised of Oregon, Washington, Idaho, western Montana and portions of California, Nevada, Utah and Wyoming. BPA sales account for approximately 45 percent of the electric power consumed in the PNW.[12] BPA also sells power that is surplus to the needs of its customers in the wholesale market to parties in the PNW, Canada and the Pacific Southwest, but primarily to parties located in California. BPA is a self-funding agency, which pays for its costs through sales of power and transmission services. Both power and transmission services are sold to its customers at cost.

On October 1, 1996, BPA separated its marketing function from its transmission function in order to avoid potential conflict of interest problems in the competitive bulk power market. BPA reorganized into four main groups: the PBL, the Transmission Business Line (TBL), the Energy Efficiency Group, and Corporate. On February 28, 1999, the Energy Efficiency Group became a part of the PBL. The PBL markets wholesale power primarily to public utilities in the Northwest, which in turn retail the power to farms, businesses and homes. Some investor owned utilities (IOUs) also buy power from the PBL. In addition, the PBL has historically sold power directly to up to 15 large PNW industrial plants, referred to as Direct Service Industries, ("DSIs"), many of

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[8] "Order on Rehearing" (Issued July 8, 2004) 108 FERC ¶ 61, 026. [FERC's July 8, 2004 Order.]

[9] FERC also issued an order "Order Implementing New Generation Market Power Analysis and Mitigation Procedures," dated May 13, 2004. In this order, the Commission addresses the procedures for implementing the new interim generation market power analysis and mitigation policy announced in the Commission's April 14, 2004 Order.

[10] FERC's April 14, 2004 Order, ¶ 117.

[11] FERC's April 14, 2004 Order, Footnote 185.

[12] BPA Facts, April 2004; Available on BPA website.

them aluminum smelters. However, during 2003 most of these plants were not operating or operating at reduced capacity.

BPA owns and TBL operates about three-quarters of the PNW's high-voltage electric grid. TBL provides open, non-discriminatory transmission services at competitive rates. Its 15,000 miles of power lines carry power from the dams and other power plants to customers of PBL and those of other suppliers for delivery throughout the PNW. TBL also has transmission links with other regions, allowing for imports and exports of power into the PNW.

BPA Generating Resources and Firm Purchase Contracts

PBL markets power generated at Federal Columbia River Power System (FCRPS) projects on the Columbia and Snake rivers. The FCRPS projects consist of 10 projects owned by the U.S. Bureau of Reclamation and 21 projects owned by the U.S. Corps of Engineers. PBL also markets the generation from seven small hydro projects owned by the City of Idaho Falls, Lewis County Public Utility District and other entities. The combined nameplate generating capacity of these hydro projects is 20,568 MW including pumped storage and non-federal hydro resources controlled by BPA.[13] In addition, PBL markets the generation from the 1,200 MW Columbia Generating Station (formerly known as WNP-2), a nuclear power plant operated by Energy Northwest, Inc.[14] Lastly, PBL markets the output from several renewable power plants, primarily cogeneration and wind turbines, under power purchase contracts with PBL. The total nameplate generating capacity available to be marketed by PBL is 22,051 MW.

In terms of rated capacities, PBL is potentially the largest marketer of electric energy supplies in the Western Electric Coordination Council (WECC) region. In addition to the generating resources under its control, PBL also had long-term power purchase contracts with 15 suppliers within the PNW of approximately 1,400 MW of capacity each month during 2003. PBL also had long-term power purchase contracts with 12 parties outside the PNW of approximately 250 MW of capacity on average each month. Adding these additional resources to PBL generating capacity would imply that PBL had approximately 24,000 MW of capacity to market during 2003. However, there are a number of factors that limit BPA ability to control the amount of energy produced by its extensive hydroelectric system.

Hydroelectric Resource Limitations

There are a number of factors that restrict how the BPA system is operated in the production of electricity. Nine of the hydroelectric projects are referred to as "run-of-the river," because they have minimal, if any, storage capacity. These nine projects have a total nameplate capacity of 11,532 MW or 56 percent of the total hydroelectric system.[15] Most of the run-of-the-river projects are downstream of large storage projects, which allow BPA some flexibility in shifting generation between periods. However, once water is released from a headwaters storage project, such as

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[13] The capacity rating of these projects was obtained from the WECC's power plant database provided in electronic form which is consistent with the December 2003 Pacific Northwest Loads and Resources Study published by BPA indicated a 20,510 MW rating for these projects due to a 56 MW derating of Cowlitz Falls hydro facilities as a result of operational restrictions in January. See White Book pg. 19-20.

[14] The BPA 2003 White Book had a 1,150 MW capacity rating for the Columbia Generating Station but to be conservative we used the name plate rating contained in the WECC database.

[15] The nine projects are Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles and Bonneville. See Columbia River System Operating Review, Final Environmental Impact Statement; Appendix I Sec. 2.2.3, Issued 11/95.

Dworshak, it's only a matter of hours before that water appears at the run-of-the-river projects on the Lower Snake River. With no storage capability on the Lower Snake River projects, the water is either used to generate electricity or it must be spilled. This means that if BPA decides to generate electricity during a specific hour from its up stream dams (with storage capacity) to take advantage of market prices, it will be forced to sell generation a few hours later from dams downstream no matter what the price.

Another factor that limits BPA flexibility is the number of non-federally owned projects downstream of the large federal projects such as Grand Coulee. These downstream projects are owned and operated by public utility districts ("PUDs") in the area. Since the operation of the federal projects will affect the operations of the PUD projects, BPA is forced to plan and coordinate the operation of its projects with these PUDs. Therefore, BPA ability to operate its system is significantly more restricted than the owners of non-hydroelectric resources.

A third factor that limits BPA flexibility is the fish flow requirements imposed by the National Oceanic and Atmospheric Administration (NOAA) FCRPS Biological Opinions. BPA and the other Federal agencies responsible for managing and operating the FCRPS are statutorily required to do so in a manner that provides "equitable treatment" for fish and wildlife alongside other purposes (such as power generation) for which the FCRPS is operated.[16] In 1995, the National Marine Fisheries Service (NMFS) (now NOAA), issued the Biological Opinion that changed the focus of the operation of the FCRPS for fish passage to seasonal flow-based targets from storage-based targets.[17] This change emphasizes the maintenance of monthly flows at hydroelectric projects, thereby limiting the ability of the system to shift and shape flows to meet generation objectives. The opinion specifies dates for achieving storage levels at the system's reservoirs and specifies the amount of water that has to be released for fish each season. The NMFS opinion noted that these requirements increase the priority for the use of reservoirs for fish flow augmentation relative to power production. On December 21, 2000, NOAA Fisheries issued a new Biological Opinion, which provided revised flow objectives that decreased rather than increased BPA flexibility in generating power from the FCRPS.[18]

In addition to having limited flexibility in the operation of its hydroelectric facilities, the productive capability of BPA facilities is also limited by the availability of water. For conventional fossil-based and nuclear generating facilities, their productive capacity is rarely, if ever, limited by fuel availability. This is not true for hydroelectric projects. As a result, the capacity rating (or instantaneous generating capacity) of a hydroelectric facility is not predictive of its productive capability in the same way that the nameplate capacity rating is for a fossil or nuclear facility.

PBL's Customers, Load Obligations and Power Sales Contracts

PBL has system sales and load obligations to federal agencies, the U.S. Bureau of Reclamation (USBR), public agencies, cooperatives, IOUs, and DSI customers within the PNW. Some of PBL's customers have other sources of generating supplies, through ownership, control or purchase contracts, and rely on PBL for only a portion of their requirements. PBL also has contracts with power marketing companies and sells or exchanges power with entities in other parts of the western U.S. and in Canada.

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[16] 16 U.S.C. 16 U.S.C.§ 839b(h)(11)(A).

[17] Biological Opinion Endangered Species Act, Section 7, Consultation by National Marine Fisheries Services Northwest Region, issued March 1995.

[18] NOAA Fisheries; "2000 Federal Columbia River Power System Biological Opinion," dated December 21, 2000.

Rate Schedules

PBL sells power to customers under five rate schedules using several types of power sales contracts (PSCs). Most of the rate schedules are restricted to specific customer groups and certain sales products.

Priority Firm Power Rate (PF-02) – is available for the purchase of firm power by customers in the PNW who belong to the following groups: public bodies, cooperatives, and Federal agencies. Power can be purchased through four basic contract types: full service, partial service, block and Slice. For non-Slice customers, the rate schedule has a monthly demand charge that is applied to the purchaser's measured demand as specified in the contract. There is also an energy charge that has two rates, one for heavy load hours (HLH) and one for light load hours (LLH), which are applied to the purchaser's entitlements during those hours as specified by the contract. The rates in the schedule are in effect beginning October 1, 2001, and are available for purchases under five-year contract with initial rates fixed for a three- or five-year period. The Slice product is priced differently than other PF products (see Section 2 below).

Residential Load Firm Power Rate (RL-02) – is available for purchases of firm power by customers in the PNW who are IOUs under net requirements contracts. Only the block contract is available under this rate schedule and the contract rates are only available under contracts for five years. The rate schedules are identical to the rates under the five-year priority firm power contract.

New Resource Firm Power Rate (NR-02) – is available for purchases of firm power by customers within the PNW who are IOUs under net requirements contracts and any public body, cooperative or Federal agency which needs power to serve any New Large Single Load (NLSL). Contracts have a five-year term starting in October 2001, with an initial fixed rate schedule available for a term of three or five years. All the basic sales contracts, except Slice, are available under the same five-year term with the same two initial fixed rate schedules.

Industrial Firm Power Rate (IP-02) – is available for purchases of firm power by BPA DSI customers for use in their industrial operations. Customers are eligible to purchase under this rate schedule for five years. Only the firm take-or-pay block contract is available under this rate schedule. The demand charge is the same as the PF rate schedule but the energy charge rates are higher.

Non-Firm Energy Rate (NF-02) – is available for the purchase of non-firm energy to be used both inside and outside the United States, including sales under the Western Systems Power Pool (WSPP) agreements and sales to consumers. The offer of non-firm energy under this schedule is determined by BPA. There are four types of rates for non-firm energy: standard, market expansion, incremental and contract. This rate will not be offered in the next rate period.

Firm Power Products and Services Rate (FPS-96R) – is available for the purchase of firm power, capacity without energy, supplemental control area services, shaping services and reservation and rights to change services for use inside and outside the Pacific Northwest. BPA is not obligated to enter into agreements to sell products and services under this rate schedule. While there is a posted rate, the actual rate may be higher or lower as mutually agreed by BPA and the purchaser.

Customer Products

Two of PBL's most significant products are its Full Service and Partial Service contracts. Full Service is available to customers who either have no resources or whose resources meet the criteria for small, non-dispatchable resources. Partial Service is available to purchasers who have contractual arrangements or generating resources with firm capabilities and therefore require a product other than Full Service to meet their power deficit. PBL had over 100 Full and Partial Service customers in 2003 with a combined peak period load of 6,558 MW.[19]

Another type of PBL product is a Block contract, which requires that a customer receives and purchases a contract-specified block of energy for every hour of the contract period (i.e., 100 percent load factor during HLH and/or LLH periods for the month). This product is available in HLH and LLH quantities per month with the hourly amount flat for all hours in such periods. There are two variations of the standard Block product, block product with Factoring and Block product with Shaping Capacity. Block product with Factoring provides the service of distributing the customer's Block energy to follow their hourly load up to the amount of energy specified by the contract. The Block product with Shaping Capacity allows the customer to pre-schedule Block energy with some limited shaping during HLH within a contractually specified bandwidth. In 2003, PBL had three customers with a Block contract under the PF-02 rate schedule. Their combined peak period load was 1,256 MW. PBL also had six DSI customers with Block contracts under the IP-02 rate schedule, however their load was approximately 570 MW during 2003 peak period.

Slice contracts are only available to public "preference" customers[20] who must purchase the Slice product combined with the purchase of the Slice Block product. The Slice Block product is similar to the Block product discussed above with a 10-year term. The Slice product differs from a traditional power sales contract in that power is made available based on the level and shape of the generation output of a set of specific Federal resources less certain Federal obligations (usually referred to as the Federal System Slice Resource Stack). These specific Federal resources include the outputs of hydroelectric projects and other resources listed in Appendix B, as well as power deliveries from the Non-Federal Canadian Entitlement Return ("CER") for the Columbia Storage Power Exchange ("CSPE"). The Federal contract obligations that are subtracted from the Federal resources include deliveries for the CER to Canada and Federal pumping loads. PBL is obligated to provide the contract specified percentage of the Federal System Slice Resource Stack to the Slice customers to meet their own load obligations or sales to third parties. The Slice product is only provided under the Priority Firm Power Rate Schedule with a fixed rate over the Fiscal Year (FY) 2002 through the FY 2006 period. The fixed monthly rate is $1,419,430 per 1 percent of the Federal System Slice Resource Stack. PBL has 25 Slice customers whose combined Slice requirements equal 22.63 percent of the Federal System Slice Resource Stack. The amount of Slice product available for delivery is dependent on the Federal system operating decisions, and hydro production, which varies by water conditions, and generation from non-hydro Federal resources.

In addition to the products just described, which are primarily (and in some cases exclusively) offered to preference customers in the PNW, PBL also sells power to IOUs, marketers and others both inside the PNW and outside the region under long-term contracts. In 2003, PBL had intra-regional long-term sales contracts with 9 customers with an average monthly capacity obligation of 1,270 MW. The six largest contracts accounted for essentially all of the capacity.[21]

During 2003, PBL also had long-term export contracts with 18 entities. Eight of these customers are public agencies in California with the others being cooperatives and power marketers. The contract terms vary from one year for two of the power marketers to 20 years for a number of the

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[19] Based on metered customers' hourly load information provided by PBL, which excluded Slice Customers' loads and segmented remaining loads depending on their location inside (5,132 MW peak) and outside (1,303 MW peak) the BPA control area (see Table VI).

[20] Public entities and cooperatives are BPA "preference" customers, which means they are statutorily granted preference and priority to the power that BPA markets. 16 U.S.C. §§ 839c(a), 832c(a).

[21] Intra-regional contracts refer to contracts for supplies and deliveries within the PNW.

public agencies. The capacity load associated with the exports varied from month to month in 2003, averaging approximately 791 MW. A number of these contracts are exchange agreements where PBL provides capacity and energy during peak periods and the buyer returns the energy during off-peak periods and provides a financial payment. These contracts allow PBL to conserve its hydro generation to be used during peak periods when the energy value is at a premium.

PBL also buys and sells power under short-term contracts to several parties within the PNW and outside the region, principally in California. In 2003, PBL entered into hundreds of forward and spot power sales contracts with terms varying from a day to several months. The spring and summer seasons were the highest sales periods with average monthly capacity sales of approximately 2,300 MW. Sales during the winter and fall seasons were half as large, averaging approximately 1,200 MW monthly. PBL had much fewer power purchase contracts for a lot less capacity during 2003. Capacity purchases average 400 MW during the winter and spring seasons, 560 MW during the summer season and 140 MW during the fall season.

Canadian Entitlement Return

The Columbia River Treaty between the United States and Canada enhanced the use of storage in the Columbia River Basin with the construction of three large storage projects in Canada. These Canadian Treaty projects provide downstream power benefits that are shared equally between the U.S. and Canada. PBL and the non-Federal mid-Columbia participants are obligated to return their share of the downstream power benefits owed to Canada. This is called the Canadian Entitlement Return (CER) to Canada. The non-Federal Canadian Entitlement obligations are delivered to PBL, which delivers both PBL's and the non-federal participants' obligations to Canada. The non-Federal entities' Canadian Entitlement obligation is included in each participating utility's load and resource balance as a delivery to PBL. During 2003, PBL's average monthly capacity obligation under the CER was 1,041 MW.

BPA Transmission System

TBL operates over 15,000 circuit miles of electric transmission lines and markets transmission services on a non-discriminatory basis to all customers in the PNW. TBL's service area includes Oregon, Washington, Idaho, western Montana and small portions of Wyoming, Nevada, Utah, California and eastern Montana. TBL's transmission lines connect to Canada, California, inland southwest and eastern Montana. BPA transmission grid provides approximately 75 percent of the PNW's high voltage transmission capacity.

There are five major paths into the BPA control area from neighboring control areas to the north, east and south. They include: (1) the Northern Intertie (NI) connecting BC Hydro, (2) the Pacific DC Intertie (PDCI) connecting Southern California, (3) the California-Oregon Intertie (COI) connecting Northern California, (4) a collection of lines to Montana, and (5) a collection of lines to Idaho. Each of these paths has been assigned a maximum transfer capability that indicates the maximum power the path can support. Based on information from BPA and a 2003 WECC report, the ratings of the paths were: 3,150 MW for the NI North to South (N-S); 3,100 MW for the PDCI S-N; 3,675 MW for the COI S-N; 2,200 MW for the Montana path E-W; and 2,400 MW for the Idaho path E-W.[22] These are the non-simultaneous ratings. Simultaneous ratings come into play

[22] Information for the COI, PDCI and NI paths was contained in the Standing Order No. 330 issued by BPA on October 30, 1998. Additional information for the COI, PDCI and NI paths is available in Attachment 2 of a report titled "1998-99 Winter Operational Transfer Capability of the California-Oregon Intertie and the Pacific DC Intertie (South to North) & Northwest Import Capability," submitted to Northwest Operational-Planning Study Group,

when there is interaction between two paths. Where there is interaction, there is some constraint that prevents both paths from being used at their respective maximum (non-simultaneous) ratings. Typically the relationship between two or more paths is represented in the form of a "nomogram." Because of the complex nature of BPA transmission system, TBL developed a simultaneous relationship between the three eastern paths, NI, PDCI and COI, while assuming specific load conditions on the two eastern paths.[23] That relationship was presented in System Dispatcher Standing Order No. 330, issued on October 30, 1998. A copy of the nomogram issued is shown in Figure 3. Based on the nomogram, the BPA system could simultaneously import 1,000 MW on the NI, 3,100 MW on the PDCI and 3,675 MW on the COI for a total of 7,775 MW. The rating of the PDCI transmission path was reduced recently due to the loss of large aluminum smelter loads in the PNW, which acted as a buffer in case there was a loss of power on the path.

Relevant Geographic Markets and First Tier Control Areas

Regional Reliability Councils and Control Areas

The North American Electric Reliability Council (NERC) has ten regional councils, shown in Figure 1. The WECC region comprises all or part of Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming, as well as the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California Norte, Mexico. One of the four sub-regions of the WECC is the Northwest Power Pool (NWPP). The sub-regions and control areas in the WECC are listed in Appendix A. The NWPP has sixteen control areas, one of which is Bonneville Power Administration Transmission (BPAT) and two of which, Alberta Electric Supply Company, LLC and B. C. Hydro & Power Authority, are in Canada. Figure 2 shows a map of the Control Areas and the Utility District Boundaries in the PNW. Compared to other areas of the country, the Northwest has many control areas.

Discussion of Geographic Markets in FERC's Orders

FERC stated that "default relevant geographic markets under both screens will be first, the control area market where the applicant is physically located, and second, the markets directly interconnected to the applicant's control area market (first-tier markets). In this default analysis, we will consider only those supplies that are located in the market being considered (relevant market) and those in first-tier markets to the relevant market. Supplies being imported from first-tier markets will be limited by simultaneous transmission import capability."[24]

In its clarification, FERC said that, "[f]or purposes of running the indicative screens, the control area includes both the control area market where the applicant is physically located, as well as the control areas directly interconnected to the applicant's control area (first-tier control areas)."[25]

September 18, 1998. Information for the Montana and Idaho paths is contained in the WECC 2005 Path Rating Catalog issued February 2005.

[23] Historical East to West loading on the Montana and Idaho transmission paths have not been very heavy during peak periods, which significantly reduced the probability of the simultaneous loading of these lines with the three other main transmission paths.

[24] FERC's April 14, 2004 Order, ¶ 73.

[25] FERC's July 8, 2004 Order, ¶ 31.

FERC further explained, "we will continue with the determination made in the April 14 Order that the approach of defining the default relevant geographic market as the control area is adequate and allow applicants and intervenors on a case-by-case basis to provide historical data and other evidence to demonstrate that, due to transmission limitations, the relevant market or markets is larger or smaller than the control area."[26]

However, FERC recognizes "that due to the integrated Western resource system, larger regional market definitions may be more appropriate, especially in the Northwest where hydroelectric power is such a critical part of the regional generation portfolio. As such, and consistent with our discussion of geographic areas above, we will allow applicants located in the Western interconnection to provide evidence that a larger geographic market definition than our control-area-by-control area approach is appropriate. Applicants making such arguments should justify their choice of market definition by citing the relevant facts and providing supporting data (i.e., historical sales indicating the actual scope of the market)."[27] But in a footnote to this statement, FERC states that, "[a]lthough we will consider such a showing, we still require that such applicants submit the generation market power screens adopted herein using the default relevant market(s)."[28]

Puget Sound Energy (Puget), an IOU located in the Seattle area, submitted a market based rate filing with FERC, using its control area market as the relevant market in both the Pivotal Supplier and the Market Share analyses.[29] However, Puget reserved the right to show that the broader PNW is the appropriate market for conducting generation market power screens in the future.[30]

In analyzing PBL's potential to exert market power, two relevant geographic markets are considered: (i) BPA control area; and (ii) the PNW region. In the first case, the relevant geographic market is BPA Control Area, which has access to a secondary market consisting of its First Tier Control Areas. In the case on the BPA market the First Tier Control Areas consist of all other Control Areas in the PNW, in addition to the California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and B.C. Hydro & Power Authority (BC Hydro). Access to this secondary market is determined by the simultaneous transfer capability between the secondary and the primary markets. In our second case, the relevant geographic markets include the entire PNW as the primary market with the secondary market, consisting of PNW's First Tier Control Areas, which are the CAISO, LADWP, and BC Hydro.

Market Analysis of BPA Control Area

As discussed above, PBL has large load obligations associated with its full service and partial service contracts, Block contracts, Intra-Regional sales contracts and Export contracts. PBL's full and partial service contracts are "load following" contracts with PBL's obligation to these customers very similar to a utility's obligation to its retail load. Therefore, for the purpose of the market power screen analyses, we have assumed the combined load of the DSIs, full service, and

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[26] FERC's July 8, 2004 Order, ¶ 35.

[27] FERC's July 8, 2004 Order, ¶ 127.

[28] FERC's April 14, 2004 Order, Footnote 111.

[29] Market Power Analysis of Puget Sound Energy, Inc., August 11, 2004, Page 3.

[30] Market Power Analysis of Puget Sound Energy, Inc., August 11, 2004, Footnote 3.

partial service customers represents PBL's "native load."[31] PBL's load obligations associated with Block contracts, intra-regional sales and export contracts of one year or more are categorized as firm long-term sales which have specific capacity obligations. PBL's load obligations associated with the Slice resource portion of the Slice contracts are taken into account through an adjustment to PBL's available generating supplies.

FERC requires that "[i]n performing all screens, applicants are required to prepare them as designed, and must use the most recent unadjusted 12 months' historical data as a snapshot in time."[32] Data for this analysis is based on the 2003 calendar year. That is the most recent calendar year for which all the required data are available.

The following section discusses the data used to determine the capacity available for wholesale sales that is required for the analysis of the two screens. This is followed by a discussion of the analysis to determine if PBL passes or fails the Pivotal Supplier screen and the Market Share screen, for each of the four seasons.

Capacity Available for Wholesale Sales

The Capacity Available for Wholesale Sales is equal to Net Supplies Available less Total Load Obligations, for both PBL and Other Suppliers within the control area plus Potential Additional Imports into the control area. Throughout this report "Other Suppliers" refers to BPA Slice customers and entities other than BPA that control generating facilities in BPA control area (or the PNW). Components of Net Supplies Available, Total Load Obligations and Potential Additional Imports are discussed below. These components are explained using the approach for calculating the screens for the BPA Control Area. The calculations for screens for the PNW are similar to those for the BPA control area.

Net Supplies Available

Net supplies available for both PBL and Other Suppliers within the BPA control area are estimated by adjusting the nameplate capacity of their generating supplies for planned outages; de-rating of hydro, wind and solar; operating reserves; and other obligations**.**

Generating Capacity

Calculations for Capacity Available for Wholesale Sales start with nameplate capacity, with amounts disaggregated by resource type. An extensive database was developed on power plants within the WECC. The primary sources for the data were the WECC and the Pacific Northwest Utilities Conference Committee (PNUCC).[33] Other data sources included PowerDat, the annual Pacific Northwest Loads and Resources Study (BPA White Book) and various other sources through the Internet. The database allowed data to be aggregated by various categories including type of generation (i.e., hydro, nuclear, etc.), ownership, and location by control area. The nameplate capacities by resource types controlled by PBL and Other Suppliers in BPA control area

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[31] In the July 8, 2004 Order, FERC allowed applicants to deduct "load following" and "provider of last resort" contracts loads from their net capacity by using the contractual peak load obligation in the Pivotal Supplier screen analysis and using the seasonal baseline demand levels served under the contract as the adjustment in the Market Share screen analysis. See ¶ 66.

[32] FERC's April 14, 2004 Order, ¶ 118.

[33] Existing Generation and Significant Additions and Changes to System Facilities 2003 – 2013 as of January 1, 2004; Western Electric Coordinating Council, issued July 2004 and PNUCC's Excel workbook "NRF Section III.xls."

are presented in Table I below. The data clearly shows the almost total reliance of the BPA system on hydroelectric supplies.

Table I

Generation Power Plant Capacity in the BPA Control Area (MW)

Power Plants in BPA Control Area	BPA Controlled Power Plants	Partial Req. Customers Power Plants	Other Suppliers Power Plants	Total Power Plants Capacity
Federal Hydro	20,131	-	-	20,131
Non-Federal Hydro	123	95	371	589
Federal Pumped Storage	314	-	-	314
Fossil Fuel - Coal	-	-	1,340	1,340
Fossil Fuel - Other & Misc.	71	6	2,183	2,260
Nuclear	1,200	-	-	1,200
Wind & Solar	174	-	-	174
Geothermal	-	-	-	-
TOTAL	22,013	101	3,894	26,007
Power Plants outside BPA Control Area				
Wind & Solar	33		9	41
Non-Federal Hydro		83	38	121

De-rating of Hydro and Wind

FERC recognized the fact that using the instantaneous or nameplate capacity of hydroelectric facilities can bias the results of the mandated market power screens, and as a result modified its approach. Therefore, FERC permits applicants to de-rate their hydroelectric capacity in conducting the two interim generation market power screens. FERC recommended the following:

Applicants that elect to do this must de-rate their hydroelectric capacity based on historical capacity factors, and they should use a five-year average capacity factor and a sensitivity test using the lowest capacity factor in the previous five years in order to more accurately capture hydroelectric availability.[34] [35]

Five-year average capacity factors for de-rating the Federal hydro system were derived from monthly hydro generation for the period 1999 to 2003. Five-year average capacity factors for hydro, other than the Federal hydro system, were similarly developed (see Table II). PBL provided historical hydro-generation data for the Federal system and data for other suppliers in WECC were obtained from Energy Information Administration's Form 860.

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[34] FERC's April 14, 2004 Order, ¶ 126.

[35] Results based on the lowest capacity factor in the previous five years are not presented. PBL passes the market screens based on average hydro conditions and would, even more easily, pass the screens based on the minimum hydro conditions.

Table II

Hydroelectric Power Plants
Average Seasonal C.F. for 1999-2003

Relevant Period	BPA	Other PNW Suppliers
Peak Month	45.1%	48.4%
Winter	44.7%	48.2%
Spring	46.0%	50.1%
Summer	45.7%	45.9%
Fall	34.4%	37.0%

For the Pivotal Supplier screen, capacity factors for de-rating were based on data for the month of February, the month in which the 2003 annual peak occurred for the BPA control area. For the Market Share screens, seasonal capacity factors for each of the four seasons were calculated and used to de-rate the Federal hydro system capacity.

Generation from wind and solar resources is also dependent on weather conditions and these resources are generally assigned zero firm capacity. FERC recognized that wind units are energy limited and allowed applicants to de-rate the available capacity of these units using a five-year average of historical output.[36] Most of the wind resources did not have 5 years of historical output. Therefore, we used the available data on facilities that had more than one year of operation to estimate an annual capacity factor, which was applied to all facilities.[37] The wind resources were de-rated by 70 percent. PBL has 206 MW of nameplate wind capacity, or one percent of its total nameplate capacity. PBL has less than 1 MW of solar capacity under contract and its average available energy was insignificant; therefore, solar capacity was de-rated by 100 percent.

Planned Outages

The Commission does not expect that applicants will have planned generation outages scheduled for the annual peak load day. However, on a case-by-case basis, FERC will consider credible evidence that planned generation outages for the peak load day of the year should be included based on the particular circumstances of the applicant.[38] Planned outages were assumed to be zero for the Pivotal Supplier screen.

For the Market Share screen, the FERC Order notes, "planned outage amounts should be consistent with those as reported in FERC Form No. 714. To determine the amount of planned outages for a given season, divide the total number of MW-days of outages by the total number of days in the season. For example, if 500 MW of generation is out for six days during the winter period the calculation of planned outages would be: (500 MW X 6)/91 or 33 MW."[39]

[36] FERC's July 8, 2004 Order, ¶ 129.

[37] The Pacific Northwest Loads and Resources Study (referred to as the White Book), published annually, is the source of the data on annual megawatts of average capacity available from wind and solar resources. The 2002 White Book and the more recently published 2003 White Book are available at http://www.bpa.gov/power/pgp/whitebook/2002/ and http://www.bpa.gov/power/pgp/whitebook/2003/.

[38] FERC's April 14, 2004, ¶ 97.

[39] FERC's April 14, 2004 Order, ¶ 100.

Table III

Planned Outages (MW)

Resource Type	Winter	Spring	Summer	Fall
Nuclear	-	377	326	-
	Winter % of Capacity	Spring % of Capacity	Summer % of Capacity	Fall % of Capacity
Coal	-	2.28	2.28	1.95
Other Thermal	-	1.44	1.44	1.23

A simplified approach for non-nuclear resources, based on percentages of installed capacity, was used. Planned outages for the Columbia Generating Station nuclear power plant are actual outages for 2003. Planned outages for thermal units are based on percent of time typically required for maintenance of thermal plants (6.5% for coal and 4.1% for other thermal plants and the monthly distribution of outage days of other power plants in the PNW. The data on percent of time are from the Energy Information Administration ("EIA").[40] The monthly distribution of outage days is based on data for several other control areas in the PNW, as reported in FERC Form 714 for the year 2003.[41] The monthly distribution was adjusted so that planned outages in the Winter season were zero. The results for the BPA control area are shown in Table III.

Planned outages are implicitly incorporated into the de-rating of hydro and wind resources. Therefore, there is no additional planned outage reduction of the hydro resources. Planned outages reduce the non-hydro supplies available during the Spring, Summer and Fall seasons.

Operating Reserves

FERC allows the State or Regional Reliability Council operating reserve requirements to be used as the default measure for the amount of capacity a supplier must keep in reserve in case of emergencies.[42] In both market screens, we used the operating reserve requirements specified by the NWPP to reduce the available operating capacity a supplier has available to sell to the wholesale market. NWPP requires operating reserves of 5 percent for hydro and wind power plants and 7 percent for thermal plants.[43] Operating reserves are required for all loads, including any potential wholesale spot sales.

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[40] Private communication with EIA, September 27, 2004.

[41] FERC Form 714 data were available for Chelan County PUD, Grant County PUD, Idaho Power Company, Northwestern Energy, Pacificorp, Portland General Electric Company,, Seattle City Light and Tacoma City Light.

[42] FERC's July 8, 2004 Order, ¶ 126.

[43] Northwest Power Pool, Operating Manual, Appendix 1, Contingency Reserve Sharing Procedure, Attachment B, Revised February 5, 2004.

Table IV

FEDERAL SYSTEM SLICE RESOURCES[44]
(MW)

Federal Hydro	19,851
Non- Federally owned Hydro	82
Pumped Storage	314
Fossil Fuel - Coal	-
Fossil Fuel - Other & Misc.	27
Nuclear	1,200
Wind & Solar	205
Geothermal	-
SLICE SYSTEM, TOTAL	21,679
Adjustments, Pivotal Supplier Screen	
planned outages	-
de-rating of hydro capacity	10,935
de-rating of wind and solar capacity	144
operating reserves	527
pumping load	314
CER	387
NET SLICE RESOURCES	9,372

Slice Resources

The capacity of the Federal System Slice Resource Stack is comprised of specific Federal resources, net of certain Federal obligations. The specific Federal resources include the generation from the Federal hydro projects, Columbia Generating Station, Georgia Pacific Corporation's Wauna Mill, Federal Non-Utility Generation; and power deliveries from the CER for Canada contracts. The capacities of these resources and the adjustments for the Federal obligations are shown in Table IV.

PBL makes available 22.63 percent of the net capacity of its Slice Resources available to its customers with Slice contracts. The capacity can be used by Slice customers to meet their own load requirements or to sell to third parties. Therefore, even though BPA may operate all of the Federal system including the Slice Resources, 22.63 percent of those resources are dedicated to Slice customers and not available to PBL for sales into the wholesale market. To account for this limitation on the amount of the Federal system that PBL is able to sell on the wholesale market, we calculated the amount of capacity dedicated to the Slice Resources, taking into consideration all of the necessary adjustments (CER, federal pumping, planned outages, de-rating and operating reserves). We then subtracted 22.63 percent of the adjusted capacity from the capacity available to PBL to meet their sales obligation and added that capacity to the supplies available to Other Suppliers (which includes Slice customers) in the control area.

Long-term Firm Intra-Regional Purchases and Imports

For this analysis, intra-regional purchases are transfers between parties within the BPA control area and parties in other control areas within the PNW, and imports are purchases by parties within the BPA control area from another party outside of the PNW. PBL's contracts for intra-regional purchases and imports with terms of one year or more are treated as long-term firm transactions. These contracts are generally not tied to specific generation. However, as firm contracts, PBL or other purchasers have a right to schedule, and the sellers have an obligation to provide the specified contract quantity to meet the purchasers' loads. Since PBL and other purchasers have control over the dispatch of the capacity associated with these contracts, we have added the contracts' associated capacity to PBL's and the other purchasers' available capacity in the analysis of both market screens.

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44 Non-federally owned hydro resources are hydro resources that are owned by other entities but assigned to or controlled by PBL. The adjustment for CER shown in Table IV is the Canadian Entitlement delivery to Canada less the non-federal CER obligation by other entities. Under current contract provisions, the Federal System Slice Resource stack is further reduced for transmission losses of 3.35 percent. For simplification, we have not taken transmission losses into account in this analysis.

Monthly data for 2003 on PBL's long-term firm intra-regional purchases were obtained from confidential data provided by PBL. PBL has 33 intra-regional contracts with 14 entities for approximately 1,400 MW of average monthly capacity during 2003. Eight of these contracts, representing 491 MW, terminated either during 2003 or at the end of 2003. Five of the contracts have no capacity associated with them reflecting the fact that they are the return contract of an exchange agreement. Under these agreements, PBL provides capacity and energy to a customer during the peak periods and the customer returns the energy in off-peak periods and pays for the use of the capacity in dollars or with additional energy. The capacity associated with many intra-regional contracts varies by month and is usually referred to as the monthly peak load.[45] A review of the load data indicates that the contracts were dispatched at an effective 100 percent load factor during HLH each month. Given the characteristics of these contracts, it is reasonable to add the contract's peak load during the system peak month to PBL's available capacity for the Pivotal Supplier screen analysis. For the Market Share screens, we used the three-month average peak load for the respective season. We had no data for intra-regional transfers for other suppliers. However, transfers between third party Suppliers do not affect the net quantities of supplies available to the Other Suppliers in our analysis.

Monthly data for 2003 imports by PBL and other suppliers in the PNW were obtained from the 2003 Pacific Northwest Loads and Resources Study. PBL had 26 long-term firm import contracts with 12 entities for approximately 250 MW of average monthly capacity during 2003. Four of these contracts, representing 29 MW, terminated during or at the end of 2003. Fifteen of these contracts had no capacity associated with them reflecting exchange energy agreements. All the contracts with associated capacity had a 100 percent load factor during HLH except for three small contracts that expired during 2003. The characteristics of these contracts for imports are very similar to the intra-regional contracts, and imports were treated similarly to intra-regional purchases for both screens. The resulting proxies for intra-regional purchases and imports as well as CER from others (discussed below) are shown in Table V.

Table V

PBL Long-term Firm Purchases and Other Supplies

	Pivotal Screen (MW)	Winter Screen (MW)	Spring Screen (MW)	Summer Screen (MW)	Fall Screen (MW)
Inter-Regional Purchases	1,727	1,611	1,152	1,196	1,489
Imports	289	327	200	163	312
CER From Others	126	154	153	186	220
Total	2,142	2,092	1,505	1,545	2,021

Canadian Entitlement Return From Others

Monthly data for 2003 on the non-Federal Canadian Entitlement obligations delivered to PBL by seventeen entities were provided by PBL. The deliveries are based on a predetermined schedule, which is set by the contract. PBL does not control the delivery of these supplies. Therefore, we decided to treat them differently from the long-term firm purchase contracts. For the Pivotal Supplier screen, the peak delivery during the control area peak month was added to PBL's resource

[45] In all cases PBL will schedule energy up to the contract capacity during heavy load hours when it makes economic sense.

capacity. We are assuming the system peak month deliveries is a reasonable approximation of the capacity PBL can rely on from these contracts to meet its load obligations during peak periods. For the Market Share screens, the average HLH delivery during the relevant seasons is added to PBL's resource capacity. In this case, we assume the average energy deliveries during HLH periods are a reasonable estimate of the capacity PBL could rely on to meet any wholesale sales. For suppliers that provide a portion of their non-Federal Canadian Entitlement from supplies within the BPA control area, their supplies were decreased using the same methodology.

Load Obligations

PBL's Total Load Obligations are the sum of: (a) the proxy Native Load inside and outside the BPA control area; (b) Slice Block sales inside and outside the control area; (c) Block sales; (d) intra-regional sales within PNW and exports from the PNW; and (e) Canadian Entitlement Return.

a. Native Load Proxy

For both market power screens, FERC allows the applicant and competing suppliers to deduct native load commitments from their net generating capacities. For the Pivotal Supplier analysis, the native load proxy is the average of the daily native load hourly peaks during the month in which the annual system peak demand day occurs.[46] For the Market Share analysis, the native load proxy is the minimum peak demand day for a given season.[47] The proxies for native loads were derived from hourly load data for the BPA control area and for the PNW.

The combined load for all suppliers inside the BPA control area was obtained from the TBL's FERC Form 714 filing. The BPA control area data were used to find the system annual peak demand day for the control area. Native load proxies for the combined load of PBL and Other Suppliers within the control area were then calculated using the FERC guidelines. PBL provided detailed hourly data for its native load (DSIs and full and partial requirements customers' loads) inside and outside the BPA control area. We determined PBL's native load proxies using its control area load coincident with the system peak and each season's minimum daily peak. The native load proxies for the Other Suppliers are the differences between the combined control area load proxies and PBL's control area native load proxies. PBL's native load proxies for loads outside the BPA control area are the loads coincident with the control area load proxies. The resulting proxy loads are shown in Table VI.

[46] FERC's April 14, 2004 Order, ¶ 88.

[47] FERC's April 14, 2004 Order, ¶ 92 ¶ 88.

Table VI

PBL Native Load Proxies

Annual Peak and Proxy Loads	Control Area Load (MW)	PBL Load Inside Control Area (MW)	PBL Load Outside Control Area (MW)	Date and Time
BPA Control Area Annual Peak	8,037	5,132	1,303	2/25/03 HE 8
Avg. Daily Peak During Peak Month	7,086	4,459	1,265	NA
Winter Minimum Daily Peak	6,049	4,017	1,111	1/3/03 HE 10
Spring Minimum Daily peak	5,496	3,309	1,082	5/23/03 HE 14
Summer Minimum Daily Peak	5,510	3,446	1,187	8/22/03 HE 11
Fall Minimum Daily Peak	5,020	3,163	1,110	9/12/03 HE 9

The seasonal daily minimal peaks used to determine the system native loads proxies are based on data for all days of the week, except Saturday, Sunday and NERC holidays.[48] The April 14, 2004 and July 8, 2004 FERC Orders did not address whether holidays and weekend days (i.e., Saturday and Sunday) should be omitted from data used to determine proxy loads. However, in an order concerning Puget Sound's market power filing, FERC states: "The Commission hereby clarifies that weekends and NERC holidays may be excluded when determining the peak load day for each season because weekends and holidays are not typical load days."[49]

b. Slice Block Sales

PBL has Slice contracts with 25 customers. Under these contracts, PBL is obligated to provide each customer with a block of energy, 24 hours per day and 7 days per week, that the customer is obligated to take to meet their own base load requirements. This is usually referred to as the "Slice block." In addition, each customer has a right to a fixed percentage of the power generated by PBL's "Slice resources." The sum of all the individual contract percentages equals 22.63 percent of PBL's total Slice resources.

PBL provided monthly data for 2003 on its block sales to the 25 Slice customers. Seventeen of these customers have some or all of their load inside the BPA control area. A review of the data indicates that the deliveries under the Slice Block contracts are constant during each month, which is consistent with the contracts. Given the structure of the data, the logical load proxy to represent these contracts in the Pivotal Supplier screen is their peak load (the same as the average MW load) during the system peak month. For the Market Share screen, we used the contracts' average monthly peak load during the relevant season as the proxy load. Since the capacity changes each month for all of the contracts, the average monthly peak load for the season may not equal the peak load in any month of the season.

Eighteen of PBL's Slice customers have some or all of their load outside the BPA control area. The proxy for the block sales outside the control area were set using the same methodology used to develop a proxy load for block sales inside the control area. For the Pivotal Supplier screen the proxy load is the sum of the contracts' peak loads during the system peak month. The proxy for the Market Share analysis is the average monthly peak load for the relevant season. The data are shown in Table VII.

[48] NERC holidays are New Year's, Memorial, Independence, Labor, Thanksgiving and Christmas days.

[49] 109 FERC ¶ 61,293, issued December 20, 2004, ¶ 92.

Table VII

PBL Proxy Load for Block Sales (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Slice Block Inside Control Area	874	893	725	697	722
Slice Block Outside Control Area	307	314	190	167	294
Block Load Outside Control Area	1,256	1,043	1,067	835	755
Total Block Loads	2,437	2,251	1,982	1,699	1,771

c. Block Sales Outside BPA Control Area

In addition to block sales to Slice customers, PBL also has block sales contracts with three other preference customers, Clark County PUD, Grant County PUD and Tacoma Public Utilities, with loads outside the BPA control area. BPA provided 2003 hourly load data for these block sales. A review of the data indicates that deliveries to Grant were at a constant 100 percent load factor each month, which made it similar to the Slice Block contracts. Deliveries to Clark and Tacoma were not constant because both contracts had an energy component above the block sale amount during HLH periods that could be shaped by the buyer. In addition to a capacity limitation that the buyer could schedule during the HLH, both contracts also had a specified amount of energy in MWH that could be delivered each day. These restrictions prevented the purchaser from scheduling the contract's total capacity at all times during the HLH periods. To maximize their benefits from the contracts both customers maximized their deliveries during HLH periods.

In developing load proxies for these contracts, we decided to treat Grant differently from Clark and Tacoma. Load proxies for Grant were developed using the same methodology used for the Slice Block contracts because of the constant 100 percent load factor shape of the deliveries. In developing load proxies for Clark and Tacoma, we decided to take a conservative approach. Both parties have the right to schedule up to their contract capacity at any hour, and PBL's obligation to deliver limits its ability to resell that capacity on the wholesale market. However, the contract's energy constraints limit the amount of HLH deliveries the parties can schedule. To take this limitation into consideration in both market screens, we have assumed that PBL's load obligations for these contracts are equal to the average load deliveries during heavy load hours. Given this assumption, the proxy loads for Clark and Tacoma used in the Pivotal Supplier analysis is the average daily peak load during the system peak month. This is assumed to be the same as the contract capacity. The proxy load for the Market Share analysis is the average contract load during the HLH periods for the relevant season. This average is invariably less than the contract capacity, which PBL believes to be its true obligation to these customers. The proxy loads for the Block customers are shown in Table VII.

d. Intra-regional Firm Sales

Intra-regional sales are defined here as transactions between PBL and parties outside the BPA control area but within the PNW. During 2003, PBL had 13 such contracts with 9 customers with a combined average monthly peak load of 1,270 MW. The two smallest contracts were with public agencies that are preference customers of PBL with contract terms of 2 to 5 years. Two energy marketers and three IOUs hold the six largest contracts, representing over 97 percent of the load. Two contracts, including the second largest contract for 200 MW, terminated during 2003. There is one exchange contract with no associated capacity that terminated in September 2004. The marketers' and all but one of the IOUs' contracts have a fairly constant 100 percent load factor

during HLH periods. The largest contract, with an average monthly capacity of 838 MW, is energy limited and has a relatively low (40%) load factor during HLH periods. Except for that one, all the other intra-regional contracts have the same characteristics of Slice Block contracts and proxy loads for those intra-regional contracts were developed using the same methodologies.[50] The proxy load for the Pivotal Supplier screen is the peak load during the system peak month. The proxy load for the Market Share analysis is the average monthly peak load during the relevant season.
The largest contract, owned by PacifiCorp, is similar to that of the Grant and Tacoma Block contract and again, being conservative, we defined its proxy load based on the same methodology. The proxy load for the Pivotal Supplier analysis is the peak load (or contract capacity) during the system peak month. For the Market Share analysis we set the proxy loads equal to the average contract load during the HLH periods of the relevant season.[51] The contract energy limitations forced PacifiCorp to schedule their full contract capacity at most 40 percent of the time during HLH periods. Therefore, while PBL has an obligation to provide the full contract capacity during any hour, we used the more conservative load proxy because during most HLH periods PacifiCorp could only schedule the full contract capacity 40 percent of the time. The results are shown in Table VIII.

Table VIII

PBL Proxy Load for Long-term Firm Sales and Deliveries (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
ITR Sales - PacifiCorp	925	358	352	317	317
Intra-Regional Sales-Others	573	348	348	353	417
Exports	751	619	573	728	642
Canadian Entitlement Return (CER)	513	648	790	948	941
Total	2,763	1,972	2,062	2,347	2,317

e. Exports

Exports are defined as sales to third party customers outside the PNW. Monthly 2003 load data for PBL's and Other Suppliers' export contracts were provided by PBL and are also contained in the 2003 Pacific Northwest Loads and Resources Study. PBL had 28 contracts with 18 entities that averaged approximately 791 MW in 2003. Ten of these contracts representing 97 MW terminated either during or at the end of 2003, while one contract representing 60 MW terminated in October 2004. Eight of the contracts representing 347 MW have effectively a 100 percent load factor during HLH periods. The remaining contracts have load factors ranging from 18 to 80 percent depending on the level of the contract energy limitation. For the contracts without energy limitations, the proxy loads for the Pivotal Supplier screen is the peak load during the system peak month. Proxy loads for the Market Share analysis are the average peak load during HLH periods for the relevant season. For loads under contracts with energy limitations, the proxy load for the Pivotal Supplier analysis is the peak delivery during the system peak month, while the proxy loads for the Market

50 Slice Block contracts have mandatory take-or-pay provisions, while intra-regional contracts have no take-or-pay provision that obligates the purchaser to schedule the contract quantities at all times.

51 The capacity associated with most of the contracts varied each month. Therefore, we considered it reasonable to use the average of the heavy load hours demand as a proxy for PBL obligation under the contract.

Share analysis are the average hourly deliveries during the HLH periods of the relevant season. The results are shown in Table VIII.[52]

f. Canadian Entitlement Return

PBL is responsible for delivering to Canada both the Federal and non-Federal Canadian Entitlement obligations. Monthly 2003 data on CER were provided by PBL and are also contained in the 2003 Pacific Northwest Loads and Resources Study. In 2003, the contract's peak load started at 642 MW in the first three months and increased to 1,171 MW for the period April through July and to 1,176 MW during the rest of the year for an annual average peak load of 1,041 MW. These changes were due to the expiration of the Canadian Entitlement Purchase Agreement (CEPA) in April 1, 2003. The CEPA allowed U.S. entities to purchase declining amounts of the energy entitled to Canada under the Columbia River Treaty, or the CER. With the expiration of the CEPA, BPA had to return all of Canada's energy entitlements. The CER contract had an 80 percent load factor during HLH periods, which implies that it had the characteristics of an energy limited contract. However, the Canadians have flexibility in determining the schedule of deliveries up to the contract maximum capacity. Given these characteristics, we developed load proxies for this contract similar to other energy limited long-term firm contracts. The load proxy for the Pivotal Supplier analysis is the peak load during the system peak month while the proxy for the Market Share analysis is the average hourly load during HLH periods for the relevant season. The results are shown in Table VIII.

Potential Additional Imports

FERC defines the relevant market as the control area market where the applicant is physically located and all interconnected first-tier control area markets. Therefore, in assessing the Market screens, FERC allows the applicant to adjust the control area capacity available to meet wholesale sales by the amount of potential imports from these first-tier markets. Potential imports equal the uncommitted capacity in first-tier control areas that can be imported into the relevant control area limited by the control area's simultaneous transmission import capability."[53] Any simultaneous transmission import capability should first be allocated to the applicant's uncommitted remote generation (i.e., capacity in the first-tier control areas). Any remaining simultaneous transmission import capability is then allocated to any uncommitted competing supplies available in the first-tier control areas. FERC did not discuss the issue, but it is also possible to increase the amount of uncommitted supplies by having customers of PBL exports redirecting these supplies to customers within the control area. This is an important source of uncommitted supplies in the BPA control area because of the significant amount of PBL exports leaving the control area.

There are sixteen control areas in the first-tier market.[54] They are listed in Table IX along with our estimates of the uncommitted supplies available in each control area. The uncommitted supplies in these first-tier markets equal the supplies available (i.e., nameplate capacity adjusted for hydro, wind and solar de-rating, operating reserves, and planned outages) less the native load. A review of the results indicates that there is over 12,000 MW of uncommitted capacity available in the first-tier

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52 Note that exports require a provision for transmission losses because of the long distance the energy has to travel. We ignored these losses in developing our load proxies which implies we are underestimating the amount of capacity necessary to service these export contracts.

53 FERC's April 14, 2004 Order, ¶ 94.

54 PacifiCorp has two control areas, PacifiCorp East and PacifiCorp West.

markets at all times to supply wholesale load.[55] The least amount of uncommitted capacity is available during the Summer peak period. Almost all of the uncommitted capacity is in California, which is represented by California ISO and LADWP, with the remainder in Montana.

As noted earlier, TBL has examined the interrelationship of the five major transmission paths into its control area. The study was based on 1 in 20 year peak loading of the Montana and Idaho paths due to the fact that historically these lines have been lightly loaded during peak periods.[56] As a result the TBL study focused on the simultaneous transfer interactions between the two paths from California and the path from Canada. That study was done in 1998 and since then the limits have not presented a problem for BPA. However, this is more likely due to the nature of imports into the PNW. Typically high PNW imports on the NI occur during peak load hours while imports on the COI and the PDCI occur during off-peak hours. Recently, for security reasons, the PDCI has been limited to 2,200 MW compared to the 3,100 MW shown in the nomogram due to the recent reduction in DSI load.[57] The DSI load acted as an interruptible load; in the event of a loss of power on the PDCI path that load could be curtailed to prevent overloading on the parallel COI path. With the large reduction in the DSI load, reliability concerns required the lower rating on the PDCI. Given this new limit on the PDCI, the simultaneous transfer limit at 1,000 MW N-S on the NI results in the COI being limited to 3,675 MW and the PDCI limited to 2,200 MW for a total simultaneous transfer capability of 6,875 MW.[58] To be conservative, the simultaneous transfer capability used in the market screens is 6,500 MW. This number is very conservative since it ignores the transfer capability on the paths from Montana and Idaho on the eastern border of the BPA control area. During peak winter periods the flows along both paths are usually well below their path ratings.[59] This would be consistent with our analysis which indicates that the Idaho market would have no surplus power during peak periods while the Montana market would have at most 1,500 MW to meet its wholesale load (see Table IX). Neither of these control areas would represent a major source of imports into the BPA control area.

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[55] The uncommitted capacity represents the amount of energy available in the control area to compete for the wholesale load. During CAISO's summer peak period, its wholesale load is approximately 10,000 MW and its uncommitted capacity is approximately 9,000 MW, This implies that CAISO would have to rely on imports during its summer peak period which is consistent past experience .

[56] There appears to be very little uncommitted capacity in eastern region of the PNW during peak periods.

[57] The loss of PBL DSI load is reflected in the change in the projected load for 2005, which was 1,750 average MW in the 2001 White Book and is now 292 average MW in 2003 White Book (see 2003 White Book, Table 8 on pg. 36).

[58] The simultaneous transfer limits assume load conditions on the west side of the system do not exceed a 1 in 20 winter peak load conditions.

[59] Based on discussions with TBL staff.

Table IX

Uncommitted Capacity in Control Areas Connected to BPA (MW)

Control Area	BPA Peak Period	BPA Winter Period	BPA Spring Period	BPA Summer Period	BPA Fall Period
Avista Corp.	(220)	35	247	100	39
B.C. Hydro & Power	(1,357)	(628)	1,158	629	(1,072)
California Independent System Operator	15,772	15,840	15,575	8,973	12,892
Chelan County PUD	(1,696)	(1,425)	(349)	(686)	(793)
Douglas County P.U.D.	156	183	264	186	162
Grant County PUD No.2	604	667	695	535	452
Idaho Power Company	(973)	(707)	(586)	(1,622)	(820)
Los Angeles Department of Water and Power	3,241	3,591	3,874	2,900	3,291
North Western Energy (Montana Power Company)	1,437	1,560	1,758	1,551	1,589
PacifiCorp East and PacifiCorp West	205	1,422	2,150	469	1,602
Portland General Electric	(1,201)	(677)	(245)	(387)	(524)
Puget Sound Energy	(2,078)	(1,480)	(803)	(791)	(1,172)
Seattle City Light	(546)	(344)	(64)	(108)	(410)
Sierra Pacific Power Co.	454	583	635	365	566
Tacoma City Light	(296)	(155)	1	(33)	(179)
TOTAL	13,501	18,466	24,311	12,078	15,622

Pivotal Supplier Screen results

The Pivotal Supplier analysis focuses on the applicant's ability to exercise market power unilaterally. It essentially asks whether the market demand can be met absent the applicant's supplies during peak times. Thus, the Pivotal Supplier screen measures market power at peak times, and particularly in spot markets. The applicant is presumed to be pivotal if demand cannot be met without some supply contribution from the applicant.[60]

The proxy for wholesale markets available to PBL and competing suppliers (i.e., "Wholesale Sales") in the BPA control area is the system annual peak load less the sum of the native load proxy for PBL and the Other Suppliers. During 2003, the BPA control area wholesale market proxy was 951 MW. The amount of uncommitted supply available to compete for the marginal supply in the wholesale market equals the total uncommitted capacity available from all suppliers in the control area minus the proxy for Wholesale Sales plus any additional imports and redirected exports (see Table X). The test for passing the Pivotal Supplier screen is a comparison of PBL's uncommitted supplies and the market's uncommitted supplies.

For the Pivotal Supplier analysis, the uncommitted capacity for PBL and Other Suppliers equals their net available supplies less their load obligations. Net available supplies equals nameplate capacity less de-rating for hydro, wind and solar operating reserves, and Slice resource sales, plus proxies for long-term firm intra-regional purchases and imports. Load obligations equal the sum of

[60] FERC's April 14, 2004 Order, ¶ 72.

the load proxies for their native load, Block loads, intra-regional sales, exports and other long-term firm deliveries. Based on the information discussed above, the uncommitted capacity available to compete for the wholesale market in the BPA control area during the 2003 system peak period is 3,127 MW as shown in Table X.

The total capacity available in the control area can be supplemented by imports based on the amount of simultaneous transfer capability available to import additional energy. In the case of the BPA control area, the simultaneous transfer capability is assumed to be 6,500 MW. However, that has to be adjusted to take into consideration PBL transmission capacity requirements for imports under firm contract plus out of area resources, or 2,212 MW.[61] In addition to physically importing energy to compete in the BPA control area wholesale market, other potential suppliers could also reschedule energy exports to customers within the control area. In our analysis, we estimate that there would be 2,763 MW of capacity exports from the BPA control area during the peak month of 2003. This implies that PBL export customers could redirect up to 2,763 MW of additional capacity to compete in the BPA control area independent of the transfer capacity into the control area. Therefore, from imports and redirected exports the total potential supplies available to supplement uncommitted supplies within the control area during the system peak is 7,051 MW. Combining the potential supplies with the Market's uncommitted capacity less the wholesale load proxy results in a net uncommitted supply available to supply marginal wholesale load of 9,226 MW.

In order to pass the screen, PBL's uncommitted capacity would have to be less than the market's net uncommitted supply. The issue of PBL passing this BPA control market screen is moot since its supply is fairly well balanced its load obligations leaving it with no uncommitted capacity during the peak period. The analysis indicates PBL could have a deficit of 730 MW during the peak period if it had to meet all its firm supply obligations. With no uncommitted capacity, PBL's ability to pass the Pivotal Supplier screen is independent of the control area's import capability. In fact, PBL would always pass this market screen as long as the Other Suppliers' uncommitted capacity is greater than the Wholesale load proxy of 951 MW.

The result of the Pivotal Supplier screen analysis is consistent with BPA most recent assessment of its load and resource balance as presented in its 2003 Pacific Northwest Loads and Resources Study. In Exhibit 2 of this study, BPA estimates it would have approximately 850 MW of supply deficit during the peak Winter months of January and February in 2005. It should be noted that the analysis is based on minimal hydro conditions (1937 Water Year), which would reduce the available hydro capacity by about 1,400 MW compared to levels during average hydro conditions.[62] However, the supply deficit derived in the analysis is based on average load conditions, which understates the load during peak periods. An analysis of the 2003 load data indicates that the average hourly load during the Winter period was 5,762 MW, while the average peak day load during the System peak period was 6,897 MW, for a difference of 1,135 MW.

[61] BPA has 70 MW of out of area resources during the peak period of 2003.

[62] Table 6 on page 21 of the Pacific Northwest Loads and Resources Study notes that going from a minimal Water Year to an 80-percentile Water Year increases hydro capacity by 1,835 MW. Therefore, it is reasonable to assume a 50-percentile Water Year would increase hydro capacity by about 1,400 MW.

Table X

BPA MARKET - PIVOTAL SUPPLIER SCREEN (MW)

	Totals	PBL	Other Suppliers
Generating Capacity	26,169	22,228	3,941
de-rating of hydro capacity,	(11,578)	(11,371)	(207)
de-rating of wind,	(157)	(151)	(6)
Operating reserves,	(773)	(533)	(240)
Slice Resource Sales	-	(2,121)	2,121
L-T Firm Purchases and Other Supplies	2,143	2,142	1
Net Available Supplies	15,804	10,194	5,609
Native Load Inside Control Area	(7,086)	(4,459)	(2,627)
Native Load Outside Control Area	(1,265)	(1,265)	-
Block Sales[63]	(1,563)	(2,437)	874
L-T Firm Sales and Other Deliveries	(2,763)	(2,763)	-
Uncommitted Capacity	3,127	(730)	3,857
Proxy for Wholesale Load	(951)		
Potential Additional Imports	7,051		
Net Uncommitted Supply	9,226		
PBL Uncommitted Capacity	(730)		
Net Uncommitted Supply less PBL	9,956		
If Positive PASS, If Not FAIL	PASS		

Market Share Screen Results

The Market Share analysis focuses on whether the applicant has a dominant position in the market, which is another indication of whether the applicant has unilateral market power and may indicate the potential to facilitate coordinated interaction with other sellers. The Market Share screen measures an applicant's size relative to others in the market during each of the four seasons, Summer, Fall, Winter and Spring.[64] FERC's Market Share analysis adopts an initial threshold of 20 percent. That is, a supplier who has less than a 20 percent market share in the relevant market in each of the four seasons will be considered to have passed the screen.[65] The 20 percent threshold is consistent with § 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P13,103 (CCH 1988).[66]

For the Market Share analysis, the relevant market is defined as the total (i.e., PBL's plus Other Suppliers') uncommitted capacity available in the control area plus any potential additional imports.

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[63] PBL's block sales to Slice Customers are considered additional resources to Other Suppliers which include Slice Customers.

[64] The months in each of the four seasons considered are: Summer (June/July/August); Fall (September/October/November); Winter (December/January/February); and Spring (March/April/May). [FERC's April 14, 2004 Order, Footnote 85].

[65] FERC's April 14, 2004 Order, ¶ 102.

[66] FERC's April 14, 2004 Order, Footnote 86.

The calculation of the uncommitted capacity is similar to that of the Pivotal Supplier analysis except the supply levels and load proxies reflect conditions during the relevant seasons instead of the system peak period. PBL's market share is then calculated as its uncommitted capacity as a percent of the relevant market total uncommitted supply for each of the four seasons.
The results for each season are shown in Table XI.

Table XI

BPA MARKET - MARKET SHARE SCREENS

	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Market's Uncommitted Capacity (MW)	5,174	5,017	4,863	3,961
Potential Additional Imports (MW)	6,310	6,985	7,234	6,740
Net Uncommitted Supply (MW)	11,484	12,001	12,097	10,701
PBL Uncommitted Capacity (MW)	748	1,027	828	73
PBL Market Share	7%	9%	7%	1%
If Less than 20% PASS, If Not FAIL	PASS	PASS	PASS	PASS

The results of the analysis clearly show that PBL is significantly below the threshold for having market power in its control area. During the Spring season, PBL had the highest amount of uncommitted capacity relative to the total uncommitted supply in the control area (21%).[67] However, given the ability to import at least 150 MW of additional supplies based on the physical simultaneous import capability of the TBL transmission system and/or displacement of exports, PBL's market share drops below the threshold.

analysis of pnw market

In its July 8, 2004 Order, FERC allowed applicants located within the Western interconnect to make a case that a larger geographic market definition is appropriate for the Market Screen analyses. BPA believes that the larger Pacific Northwest market is the appropriate market for assessing its ability to exert market power. BPA, and more specifically its marketing subsidiary, PBL, has firm power sales contracts with customers in every control area in the PNW except Alberta Electric in Canadian.[68] During peak periods, over 40 percent of PBL's firm sales go to customers outside its control areas either in the PNW or California (see Table XII).[69] In addition, as we noted earlier, the BPA control area is physically connected to every other control area in the PNW. BPA total integration into the PNW is highlighted by its annual publication of the Pacific Northwest Loads and Resources Study. The report summarizes the results of a ten (10) year study that simulates the operation of the power system under the Pacific Northwest Coordination Agreement. The study projects the yearly average energy consumption and resource availability for the 10-year study period. For BPA, the Pacific Northwest Loads and Resources Study establishes one of the planning bases for supplying electricity to customers.

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[67] The 21% results from dividing PBL's uncommitted supply of 1,027 MW by total uncommitted supply in the control area 5,017 MW.

[68] PBL has no direct connection to Alberta Electric control area.

[69] This includes full and partial requirements customers, block customers and customers with long-term firm contracts.

Table XII

PBL Long Term Firm Sales Distribution During 2003 Peak

Customer Group	Inside BPA Control Area	Outside BPA Control Area	Total
Native Load	5,132	1,426	6,558
Slice Load	1,445	669	2,114
Slice Block Sales	874	307	1,181
Block Sales		1,256	1,256
Inter-Regional Sales		925	925
Exports		751	751
TOTAL	7,451	5,334	12,785
Distribution	58%	42%	

Conducting the Market Screen analyses for the PNW market is a repeat of the analyses done for the BPA control area except the loads and resources of the Other Suppliers are expanded to include those of suppliers in the other control areas of the PNW. PBL resources and loads used in the Market Share screens will only change to reflect the coincident peaks of the PNW region instead of the BPA control area.

PNW Capacity Available for Wholesale Sales

The capacity available for the PNW Wholesale market is equal to Net Supplies Available less Total Load Obligation for all suppliers in the region. We have already discussed the capacity available to PBL. Therefore the following discussion will focus on the Other Suppliers.

Available Supplies

Information on the generating capacity of suppliers in the PNW was obtained from the WECC, PNUCC, the BPA Pacific Northwest Loads and Resources Study and other sources. The resulting data are illustrated in Table XIII below.

Table XIII

Generation Power Plant Nameplate Capacity in the PNW (MW)

Type of Power Plant	PBL Controlled Power Plants	Partial Req. Customers Power Plants	Other Suppliers Power Plants	Total Power Plants Within the PNW
Federal Hydro	20,131	-	-	20,131
Non- Federal Hydro	123	178	13,024	13,325
Federal Pumped Storage	314	-	-	314
Fossil Fuel – Coal	-	-	12,052	12,052
Fossil Fuel - Other & Misc.	71	6	9,168	9,245
Nuclear	1,200	-	-	1,200
Wind & Solar	206	-	513	719
Geothermal	-	-	195	195
TOTAL	22,045	183	34,952	57,180

The table indicates that the nameplate capacity of generation resources marketed by PBL represents approximately 39 percent of the generation nameplate capacity of power plants in the PNW. However, as we have noted earlier, nameplate capacity is not a good indicator of the available capacity, especially for hydroelectric power plants. Following FERC's guidelines, we de-rated hydro and wind facilities in the PNW based on the last five years of hydro operations and available data for wind generation. We also adjusted both PBL's and Other Suppliers' capacity for operating reserves and planned outages using the same methodology discussed earlier for the BPA market screens.

Data on Other PNW Suppliers' long-term firm imports into the PNW was obtained from BPA 2003 Pacific Northwest Loads and Resources Study.[70] An analysis of the data indicates that Other Suppliers had an average of 738 MW of capacity under firm long-term import contracts during 2003. The capacity was utilized at a 51 percent capacity factor during heavy load hours. The relatively low utilization does not change the fact that the purchaser had the right to schedule the contract's full capacity at any time. Therefore, we assumed for both the Pivotal Supplier and the Market Share screens that the purchasers had access to the full contract capacity, which was added to the suppliers of the Other Suppliers in the market.

Load Proxies

The methodology used to develop load proxies for the PNW is similar to the ones described above for the BPA market. Hourly load data for the PNW region during 2003 was obtained from PBL. An analysis of the data indicates that the annual peak of the PNW system is coincident with the peak of the BPA control area. The 2003 peak load for the PNW region was 33,580 MW and the average daily peak during the February peak month was 31,638 MW resulting in a proxy wholesale load of 1,941 MW (see Table XIV).

Table XIV

PNW Native Load Proxies

Annual Peak and Proxy Loads	Control Area Load (MW)	PBL Load Inside Control Area (MW)	Date and Time
PNW Control Area Annual Peak	33,580	6,435	2/25/2003 HE 8
Avg. Daily Peak During Peak Month	31,638	5,725	NA
Winter Minimum Daily Peak	28,049	4,912	12/24/2003 HE 10
Spring Minimum Daily Peak	25,950	4,356	5/22/2003 HE 11
Summer Minimum Daily Peak	26,884	4,473	7/3/2003 HE 15
Fall Minimum Daily Peak	25,140	4,280	9/19/2003 HE 11

In the analysis of both PNW screens, the load proxy for intra-regional sales by PBL are treated as supply additions for Other Suppliers and supply additions due to intra-regional purchases by PBL are treated as loads due to long-term sales by Other Suppliers. Data on Other Suppliers' exports from the PNW was also obtained from BPA Pacific Northwest Loads and Resources Study. Analysis of the data indicates that Other Suppliers had long-term firm contracts to export, on average, 801 MW of capacity in 2003. Their average hourly export was 675 MW for an 84 percent capacity factor. To be conservative, we assumed that buyers have control in terms of scheduling deliveries under the contracts. Therefore, in both screen analyses the load associated with these export contracts equals their peak delivery during the system peak month for the Pivotal Supplier screen and the average monthly peak delivery for the relevant season in the Market Share screen. The proxies for Other Suppliers' imports and exports are shown in Table XV.

[70] Intra-regional transfers between Other Suppliers have no impact on the overall supplies available in the region, and any intra-regional sale or purchase by PBL results in a purchase or sale, by the Other Suppliers.

Table XV

Other PNW Suppliers' Transactions (MW)

	Pivotal Screen	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Exports	686	704	696	944	861
Imports	979	1,106	573	388	884

Potential Imports

In the case of the PNW market, the main first-tier control areas consist of BC Hydro to the north, and CAISO and LADWP to the south. To the east PNW is interconnected to the Mid-Continent Area Power Pool (MAPP), through a number of small DC transmission lines whose combined rating is approximately 700 MW.[71] Since the transfer capability on this path is relatively small, control areas to the east of the PNW were ignored and our analysis only considered the three major control areas to the north and south. A review of Table XVIindicates that only the CAISO and LADWP are able to provide any significant amount of additional supplies to the PNW region. The two regions have approximately 20,000 MW of uncommitted capacity during the winter and spring seasons and approximately 12,000 MW in the summer and fall. In the summer the uncommitted capacity reduces to around 11,000 MW. It should be emphasized that uncommitted capacity does not represent surplus energy but energy that is available to compete for wholesale load in the primary control area and all connected markets. Given the large size of the BPA control area, the five major paths into its system are the same major paths into the PNW. Therefore, we have used the same simultaneous transfer capability for the PNW that we used for the BPA control area based on the same set of paths.

Table XVI

Uncommitted Capacity in Control Areas Connected to PNW (MW)[72]

Control Area	Peak Period	Winter Period	Spring Period	Summer Period	Fall Period
B.C. Hydro & Power	(1,357)	(626)	1,158	629	(561)
California Independent System Operator	15,772	16,062	15,575	8,973	9,860
Los Angeles Department of Water and Power	3,241	3,625	3,874	2,900	3,104
TOTAL	17,655	19,061	20,608	12,501	12,403

Results of Market Screens

The results of the Pivotal Supplier screen for the PNW market are illustrated in Table XVII. The table reaffirms the earlier results of the BPA control area screen that PBL does not have market power during peak periods. As was noted earlier, PBL does not appear to have any uncommitted capacity during the BPA control area peak period which is the same as the PNW peak period in 2003. Therefore, it will not have the supplies to exert market power during peak periods.

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[71] WECC Power Supply Assessmet, June 16, 2004.

[72] The uncommitted capacity for the control areas differ from Table IX because the time of the seasonal peaks in the PNW differ from that of the BPA control area.

Independent of BPA uncommitted suppliers, if Other Suppliers have uncommitted supplies exceeding Wholesale proxy load of 1,941 MW, then BPA will automatically pass this screen. Given the large amount of uncommitted supplies held by Other Suppliers in the PNW market it would be difficult for BPA to exert market power during peak periods in the PNW.

Table XVII

PNW MARKET - PIVOTAL SUPPLIER SCREEN (MW)

	Totals	PBL	Other Suppliers
Generating Capacity	57,180	22,228	34,952
de-rating of hydro capacity,	(17,964)	(11,371)	(6,592)
de-rating of wind,	(511)	(151)	(360)
Operating reserves,	(2,247)	(533)	(1,715)
Slice Resource Sales	-	(2,121)	2,121
L-T Firm Purchases and Other Supplies	4,494	2,142	2,352
Available Supplies	40,952	10,194	30,758
Native Load Inside PNW	(31,638)	(5,725)	(25,914)
Block Sales	-	(2,437)	2,437
L-T Firm Sales and Other Deliveries	(5,175)	(2,763)	(2,413)
Uncommitted Capacity	4,139	(730)	4,869
Proxy for Wholesale Load	1,941		
Potential Additional Imports	8,450		
Net Uncommitted Supply	10,647		
PBL Uncommitted Capacity	(730)		
Net Uncommitted Supply less PBL	11,377		
If Positive PASS, If Not FAIL	PASS		

The results of the Market Share screen for the PNW market are illustrated in Table XVIII. The results of the Market Share screen once again show that PBL is significantly below the threshold for having market power, this time in the PNW market. This is not surprising since PBL did not have market power in the BPA control area where most of its resources are located. In the PNW market, PBL's highest market shares occur in the Winter, which is the peak demand period for the region, and in the Summer. PBL's highest share of the PNW market's uncommitted capacity (15 percent) occurs in the Summer season.[73] Therefore, if we were to ignore imports in this market share analysis, PBL's highest market share would be only 15 percent and it would still pass the market screen.

[73] The 15% results from dividing PBL's uncommitted supply of 988 MW by total uncommitted supply in the region 6,562 MW.

Table XVIII

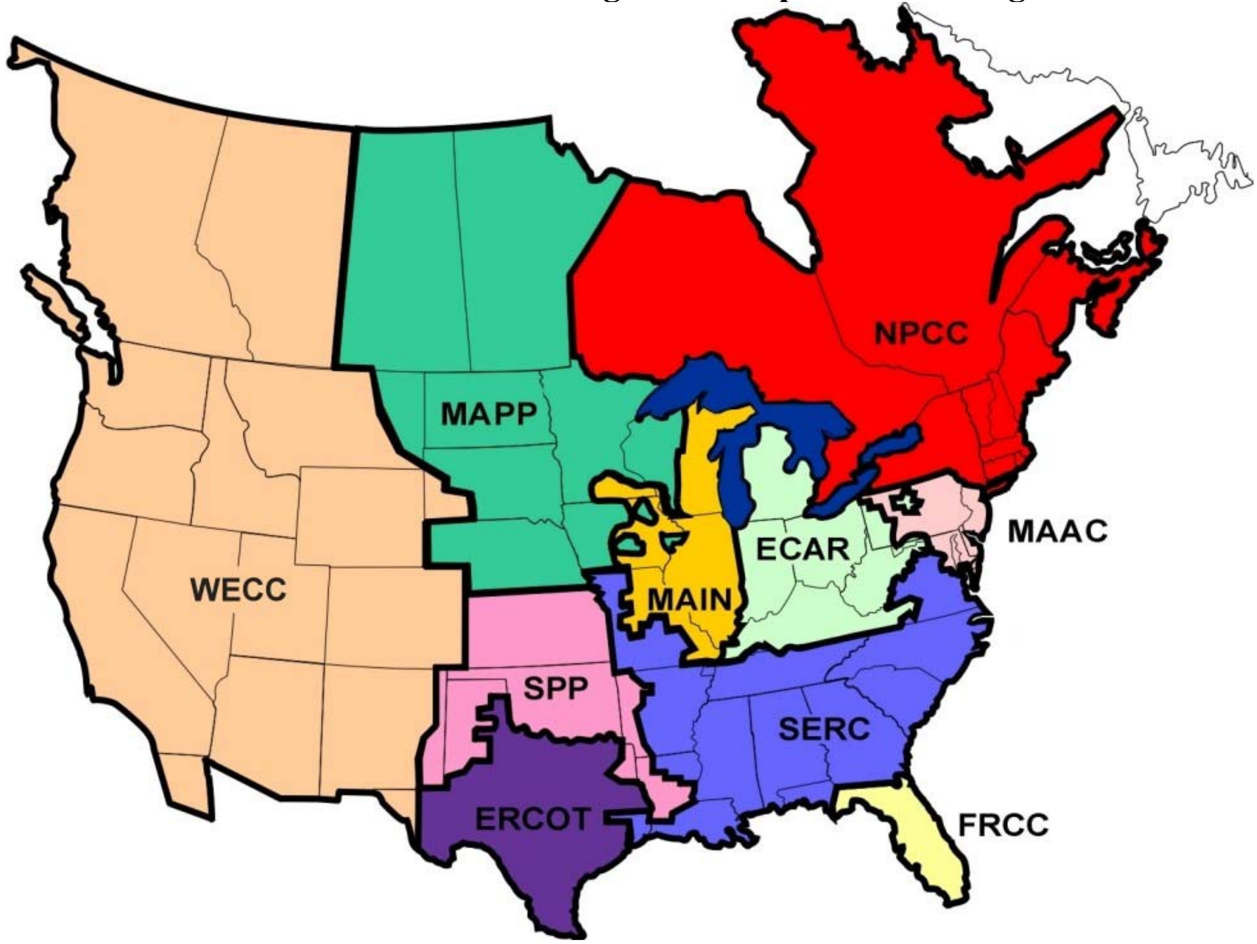
PNW MARKET - MARKET SHARE SCREENS

	Winter Screen	Spring Screen	Summer Screen	Fall Screen
Market's Uncommitted Supply (MW)	7,760	8,839	6,562	6,144
Potential Additional Imports (MW)	7,037	7,785	8,569	7,748
Net Uncommitted Supply (MW)	14,796	16,624	15,131	13,892
PBL Uncommitted Supply (MW)	964	1,063	988	66
PBL Market Share	7%	6%	7%	0%
If Less than 20% PASS, If Not FAIL	PASS	PASS	PASS	PASS

Conclusions

This Market Power Study has analyzed the whether the marketing division of BPA has the ability to exert market power based on two screens recently proposed by the Federal Energy Regulatory Commission. PBL passes both the Pivotal Supplier screen and the Market Share screen in both the BPA control area market and the larger PNW market. The Pivotal Supplier analysis examines the ability of PBL to exert market power during the peak winter period in both markets. The results indicate that the capacity of PBL's dependable long-term supplies matches its long-term contract capacity obligations during the peak periods. Therefore, instead of exerting market power, PBL may have to acquire some limited amount of short-term supplies if it were required to meet all its contracted long-term capacity obligations during the winter peak periods. The Market Share analysis examines the ability of PBL to exert market power alone or in combination with Other Suppliers during each of the four seasons of the year. The analysis calculates PBL's market share in each season and compares it to a 20 percent threshold. PBL passed the test in all seasons in both the BPA control area market and the larger PNW market. In passing the screen for the PNW market, PBL need not rely on any potential imports into that market. In the case of the BPA control area market, passing the Market Share screen requires the availability of 150 MW of import capacity. However, a very conservative estimate of the simultaneous import capability for the BPA control area is 6,500 MW. Based on the principles established in the April 4 Order and the July 8 Order, PBL does not possess horizontal generation market power in either BPA control area market, or in the broader PNW market.

Figure 1: Map of NERC Regions



East Central Area Reliability Coordination (ECAR)
Electric Reliability Council of Texas (ERCOT)
Florida Reliability Coordinating Council (FRCC)
Mid-Atlantic Area Council (MAAC)
Mid-America Interconnected Network (MAIN)
Mid-Continent Area Power Pool (MAPP)
Northeast Power Coordinating Council (NPCC)
Southeastern Electric Reliability Council (SERC)
Southwest Power Pool (SPP)
Western Electric Coordination Council (WECC)

Figure 2: Pacific Northwest Control Areas and Utility District Boundaries

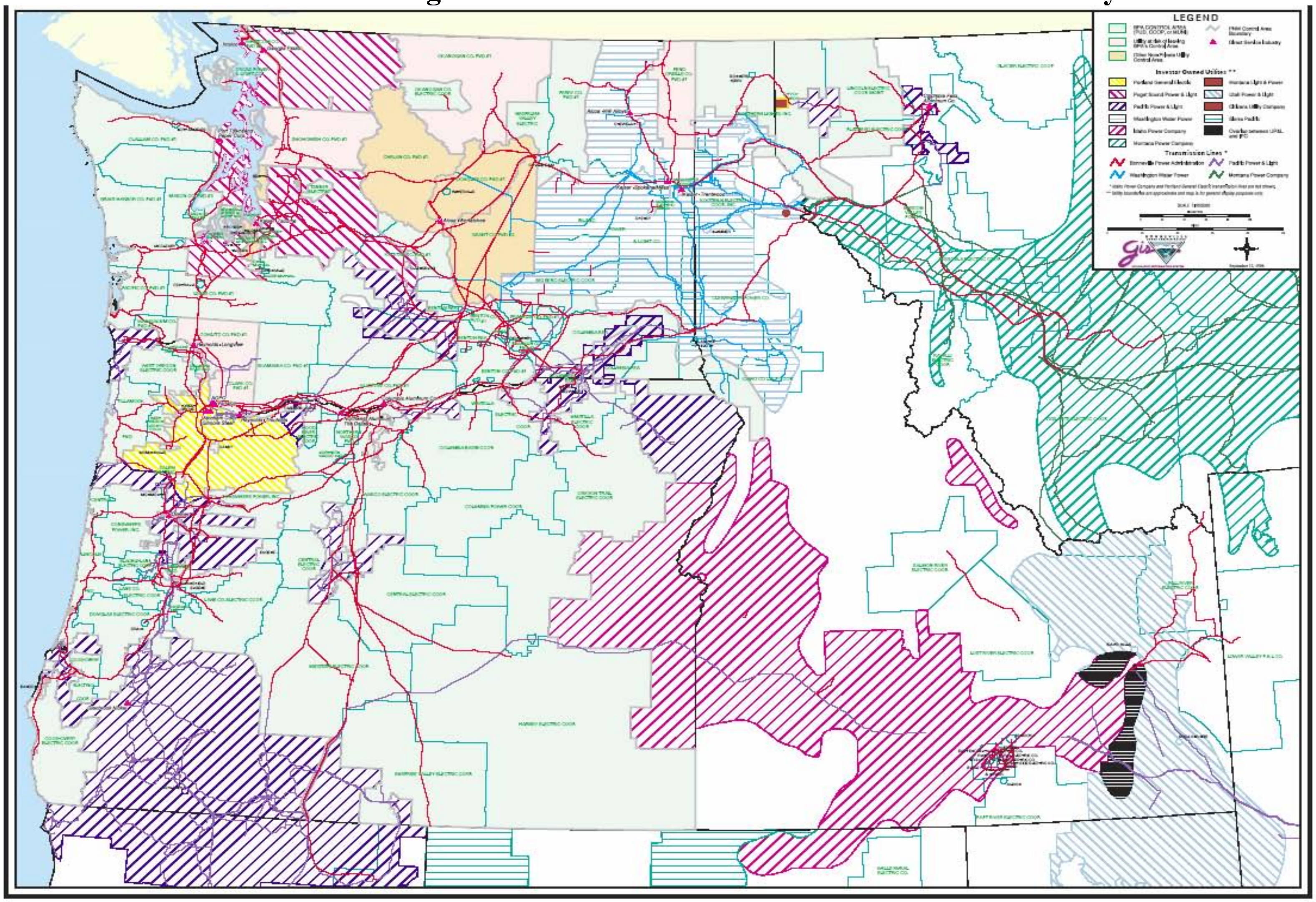
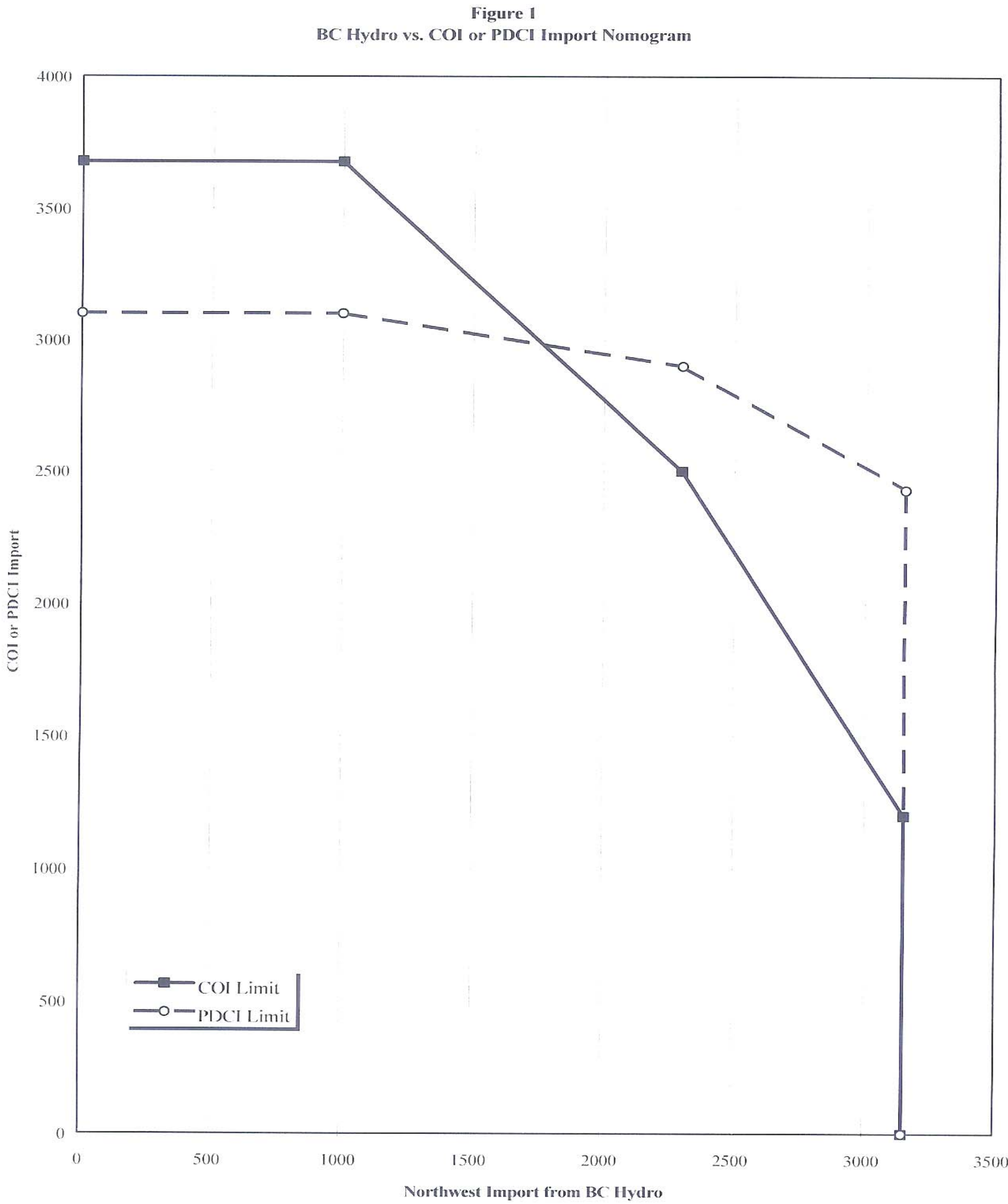


Figure 3: PNW Nomogram



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Appendix A: WECC Sub-regions and Control Areas

AZNMSNV	Arizona Public Service Company	AZPS
	DECA, LLC - Arlington Valley	DEAA
	El Paso Electric	EPE
	Imperial Irrigation District	IID
	Nevada Power Company	NEVP
	Public Service Company of New Mexico	PNM
	Salt River Project	SRP
	Tucson Electric Power Company	TEPC
	Western Area Power Administration – DSW	WALC
CAMX	California Independent System Operator	CAISO
	Comision Federal de Electricidad	CFE
	Los Angeles Department of Water and Power	LDWP
	Sacramento Municipal Utility District	SMUD
NWPP	Alberta Electric Supply Company, LLC	AESO
	Avista Corp.	AVA
	B.C. Hydro & Power Authority	BCHA
	Bonneville Power Administration Transmission	BPAT
	Chelan County PUD	CHPD
	Grant County PUD No.2	GCPD
	Idaho Power Company	IPCO
	Montana Power Company	MPCO
	P.U.D. No. 1 of Douglas County	DOCA
	PacifiCorp-East	PACE
	PacifiCorp-West	PACW
	Portland General Electric	PGE
	Puget Sound Energy Transmission	PSEI
	Seattle City Light	SCL
	Sierra Pacific Power Co. – Transmission	SPPC
	Tacoma Power	TPWR
	Western Area Power Administration – UGPR	WAUM
RMPA	Public Service Company of Colorado	PSCO
	Western Area Power Administration – CM	WACM

Source: http://www.nerc.com/~filez/ctrlareas/acronymsPage4.html (Downloaded 9/9/04, Information dated November 5, 2002)

Appendix B: Slice System

1. **HYDROELECTRIC PROJECTS**

(a) Projects Currently with Flexibility
Mica (storage only, no at-site generation)
Arrow (storage only, no at-site generation)
Duncan (storage only, no at-site generation)
Grand Coulee
Chief Joseph
McNary
John Day
The Dalles
Bonneville
Lower Granite
Little Goose
Lower Monumental
Ice Harbor
Big Creek

(b)..Cyclic Projects

Dworshak
Hungry Horse
Libby
Albeni Falls

(c) ....Minor Projects

Chandler
Cowlitz Falls
Roza

(d)...Southern Idaho Projects

Anderson Ranch
Black Canyon
Boise Diversion
Idaho Falls Projects
Minidoka
Palisades

(e) ....Willamette Projects

Big Cliff
Cougar
Detroit
Dexter
Foster

Green Peter
Hills Creek
Lookout Point
Lost Creek

2. THERMAL AND MISCELLANEOUS RESOURCES
CGS (formerly WNP-2)
Wauna
Foote Creek Wind Turbine Projects
Grand Coulee Pumps
Dworshak/Clearwater Small Hydro Power
Green Springs
Stateline (90.42 MW of installed capacity and associated energy)
Condon
Klondike
Ashland Police Station Solar
White Bluff
Fourmile Geothermal Project (Available in 2006)

3. CONTRACTS

Non-Treaty Storage Agreement
Chief Joseph Encroachment
Albeni Falls Encroachment

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APPENDIX D

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 E
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

<u>aMW Target Gap Proposal</u>: 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.

Administrative Allowance Proposal: 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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 F
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.

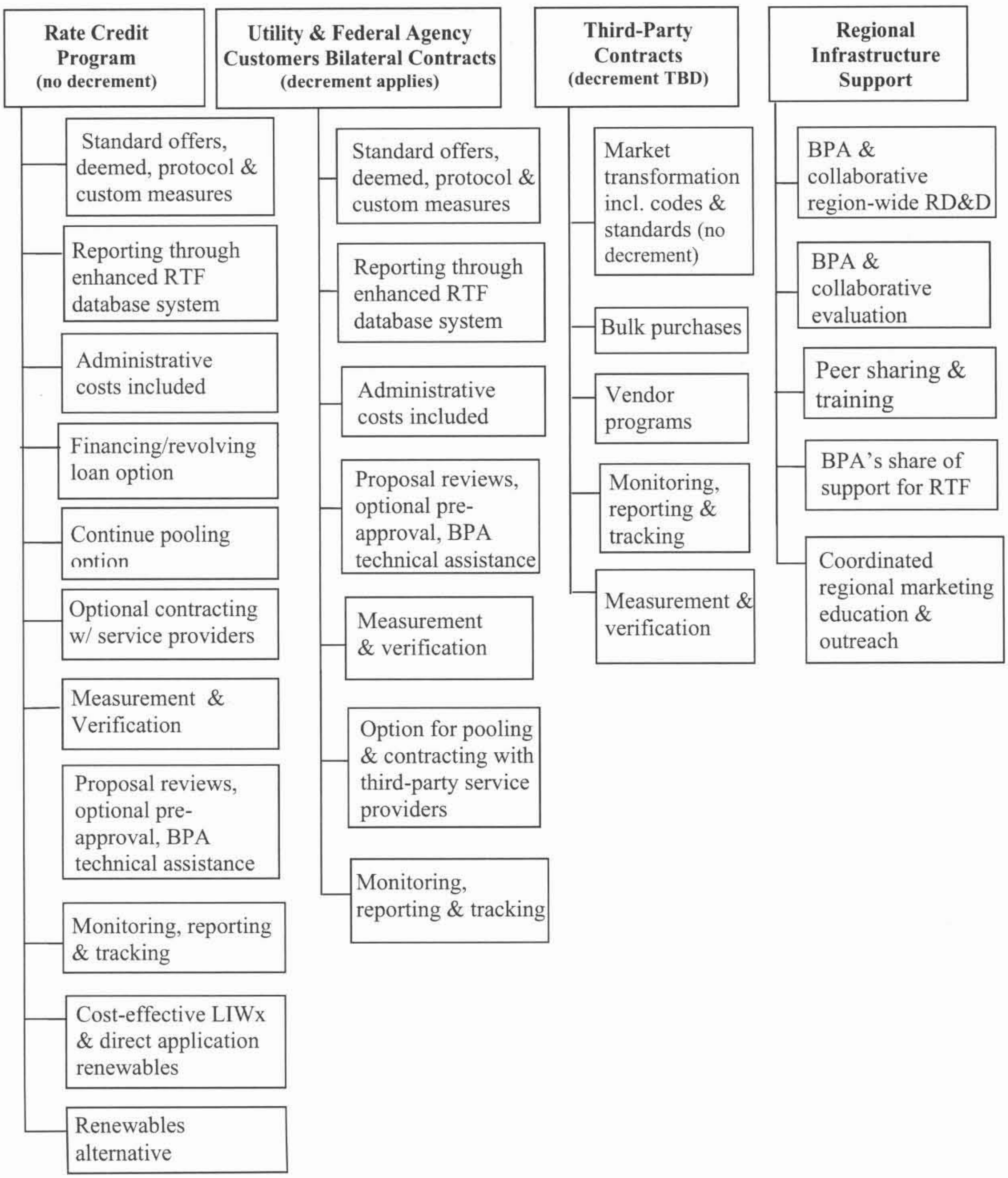
II. Program Portfolio and Structure

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



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

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

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

Eligibility

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

Incremental Requirements

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

Decrement

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

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

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

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

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

Table 1: Program Annual aMW Targets and Budgets

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

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

** Includes a 15 percent administration allowance.

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

Features Consistent For All Programs

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

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

Rate Credit Program

Overview

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

Key Features

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

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

Rate Credit Eligibility

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

Small Utility Option

Overview

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

Utility and Federal Agency Bilateral Contracts Program

Overview

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

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

Key Features

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

Measure Eligibility

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

Third-Party Contracts

Overview

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

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

Key Features

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

Infrastructure Support

Overview

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

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

Tracking and Reporting

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

Appendix 1
Sample of Reporting, Oversight, and Evaluation Requirements

Reporting:

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

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

Oversight and Verification:

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

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

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

Evaluations:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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ERRATA

Errata to
WP-07 Supplemental Power Rate Case
FY 2009 Wholesale Power Rate Development Study Documentation
WP-07-FS-BPA-13A

Delete pages A-3 to A-4, renumber Appendix A pages.